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ENGINEERING DEPARTMENT

2009 APR 15 A 10: 28

AZ CORP COMMISSION
DOCKET CONTROL

DATE: 13 April 2009

Arizona Corporation Commission
DOCKETED
APR 15 2009
DOCKETED BY

Arizona Corporation Commission
Attention: Docket Control
1200 W. Washington
Phoenix, Arizona 85007

Re: Time of Use and Smart Metering Infrastructure; Compliance Item to Decision No. 70696; Docket Nos. E-01891A-08-0061 and E-02044A-08-0061

Dear Sir/Madam:

I am the Engineering Manager for Garkane Energy Cooperative, Inc. ("Garkane"). I am supplying this information in compliance with the third ordering paragraph of Decision No. 70696 which required Garkane by no later than 15 April 2009 "provide Commission's Docket Control with copies of detailed quotes, analysis, findings, and recommendations that support Garkane Energy Cooperative, Inc. ... regarding the feasibility of offering time-based rate schedules and such support shall include at least three meter quotes from three different suppliers, and at least one supplier quote to upgrade the existing TS1 and billing systems to accommodate appropriate AMR/TOU meters.". The Order further requires Garkane to provide "Commission's Docket Control with draft copies of the proposed time-based rate schedules, including detailed supporting data within nine months of the Commission's decision in this docket."

On 30 January 2009, Garkane filed preliminary cost estimates to implement a Time of Use – Net Metering – Smart Metering Program. Garkane is herewith submitting site specific implementation costs, and a specific cost analysis of the programs.

Item 1 attached, is a Memo from Craig Twitchell, Meter Technician, dated 31 March 2009 detailing the efforts made to use the existing TS1 system in a TOU or Net

Metering Application and the problems encountered. After extensive work with Landis+Gyr (the current manufacturer of the TS1 and TS2 systems) and National Information Services Cooperative "NISC" (the provider of Garkane's Customer Accounting Software package "IVUE") the conclusion was reached, that given a TS1 compatible meter with the appropriate TOU or Net Meter registers, the combined system is capable of correctly reading and billing residential TOU accounts with a single on peak – off peak block. This limitation is due to restrictions in the interface between Command Center (the L+G Software that controls the TS1 and TS2 systems) and NISC IVUE system. Eliminating these restrictions in the TS1 interface will require a complete redesign/rewrite of the interface because of the major change in logic and data structure. These limitations have been resolved in the TS2 version of the interface. NISC and L+G both recommend that if Garkane needs to implement TOU and Net Metering on a large scale that we should upgrade to the TS2 system as the TS1 / IVUE combination is not compatible with the TOU and Net Metering functions.

Item 2 attached, is a letter from Lowell Alt (Rate Consultant) dated 8 April 2009 which outlines the analysis of TOU and Net Metering costs and benefits which he analyzed for Garkane.

Item 3 attached, is a Cost of Service Study prepared for Garkane by Lowell Alt which looks at potential TOU and Net Meter Rates.

Item 4 attached, is a summary of TOU Conversion Benefit/Cost Ratios.

Item 5 attached, is a summary of Advanced Metering Costs.

Item 6 attached, is a summary of proposed rates with and without TOU rates.

Item 7 attached, is a calculation of Garkane Fixed Charge Rate Calculations.

Item 8 attached, is a summary of the Estimate of Residential TOU Conversion Benefits.

Item 9 attached, is an estimate of all non-lighting TOU Conversion Benefits.

Item 10 attached, is a Cost Analysis Summary of TOU rates.

Item 11 attached, is a analysis of the Revenue Requirement Impact of Proposed Advanced Metering Infrastructure.

Item 12 attached, are graphs of the Typical Deseret Power (DGT) Daily Load Profile for Summer and Winter.

1802 South Highway 89A, Kanab, Utah 84741
Voice: (435)644-5026 Fax: (435)644-8120
E-mail: mavant@garkaneenergy.com

Item 13 attached, is an analysis of the date and time of the Deseret Power (DGT) Coincident System Peaks for the years 2004 through 2008 and the system peaks for Dixie-Escalante and Garkane Cooperatives.

Item 14 attached, is a list of potential benefits for TOU rates for Garkane, the Customer, and Societal benefits.

Item 15 attached, is a cost estimate from Landis+Gyr "L+G" to provide the L+G parts necessary to upgrade the Fredonia and Ryan Substations form TS1 to TS2 systems. The Fredonia and Ryan Substations are the two Garkane 69 kV Substations which serve loads in Arizona. The Colorado City Substation also feeds load in Arizona. After analysis L+G believes the meters out of the Colorado City Substation can be read with the equipment to be installed in the Fredonia Substation. .

Item 16 attached, is a cost estimate for Garkane to provide the balance of materials necessary to install the TS2 equipment at the Fredonia Substation and to install the L+G provided TS2 equipment.

Item 17 attached, is a cost estimate for Garkane to provide the balance of materials necessary to install the TS2 equipment at the Ryan Substation and to install the L+G provided TS2 equipment.

Item 18 attached, is a memo from Mike Avant, Engineering Manager, dated 1 April 2009 summarizing the L+G TS1 to TS2 upgrade process and associated expenses. This information was provided to Lowell Alt for use in the preparation of the cost analysis.

Item 19 attached, is a proposal from Stellar Grants to prepare a ARRA "Stimulus Bill" Grant application for a 50% matching grant to reimburse 50% of the cost of the TS2 system.

Item 20 attached, is a cost estimate from Northern Power to supply Landis+Gyr meters for TOU and Net Metering capable meters. The quote lists TS1 modules, the prices for TS2 modules is listed in the price quote from L+G.

Item 21 attached, is a cost estimate from Northern Power to supply General Electric "GE" meters for TOU and Net Metering capable meters. The quote list TS1 modules the prices for TS2 modules is listed in the price quote from L+G.

Item 22 attached, is an email from Ross Howells with Riter Engineering (our Itron

1802 South Highway 89A, Kanab, Utah 84741
Voice: (435)644-5026 Fax: (435)644-8120
E-mail: mavant@garkaneenergy.com

Distributor) stating that Itron does not offer single phase Net, TOU, or Demand meters. They can only provide three phase meters with a KYZ output to be used with an external TS2 module. We have been unable to get any prices from Riter Engineering for the requested Itron meters.

Lowell Alt in his report summarizes

> "The results of the Benefit/Cost model show all alternatives and variations have a benefit/cost ratio (BCR) less than "1", with the best alternative being Alternative 1 (keep TS1) with a BCR=0.84."

This option would limit the application of TOU and Net Metering to Residential customers only, while maintaining the existing AMR system. Demand billed customers would have to be manually read and hand billed, thus defeating the purpose and effectiveness of the AMR system currently in place. 80% of Garkane's Arizona customers are Residential class.

The Cost of Service Study (Item 3) was utilized by Lowell Alt to:

> "Cost data from the cost of service study, the AMI Cost Analysis and expected incremental demand costs were used to design individual rate elements for both TOU and non-TOU rates. For demand-metered rates, a single energy price was used based on the average cost of energy plus the primary and secondary demand costs. For residential, a peak and off peak energy price was used based on average costs (energy and demand) for those periods. For demand-metered rates, the peak demand price was based on the expected incremental demand cost adjusted for estimated demand losses. The proposed rates are included in two separate files named "2009 AZ Rate Proposal" (uses 8-31-08 billing units to calculate expected revenues) and "AZ TOU Prices"(which simply shows the TOU rate elements for each rate schedule as well as the peak period definition). I assume development of the actual rate schedule sheets can be done later. The objective is to design the rates to recover the appropriate costs while providing an incentive for customers to shift load off peak. The AMI cost analysis assumes the incentive is no more than the cost avoided."

Because of the constraints detailed above, Garkane only recommends the implementation of TOU rates shown in Item 6 for residential customers.

Attached as item 23, is a proposed Net Metering rate. As written this rate could be applied to all rate classes. Because of 1) the meter/billing system constraints detailed above, 2) the high cost of implementation of the new meter system necessary for demand billed customers, and 3) 80% of Garkane's Arizona customers are Residential class, Garkane recommends that the applicability of this rate be limited to Residential class customers who are not also on the TOU rate.

Garkane does not at this time recommend the implementation of a "Smart Metering System" (TS2) due to the low Cost/Benefit ratios derived from the analysis.

Should you have any questions concerning our plans, please contact me at mavant@garkaneenergy.com.

Very truly yours,

M Avant

Mike Avant
Engineering Manager

Enclosures

Original and 15 copies mailed this _14__day of April, 2009 to Arizona Corporation Commission Docket Control

1802 South Highway 89A, Kanab, Utah 84741
Voice: (435)644-5026 Fax: (435)644-8120
E-mail: mavant@garkaneenergy.com

ENGINEERING DEPARTMENT

DATE: 31 March 2009

TO: Mike Avant, Engineering Manager

FROM: Craig Twitchell, Meter Technician

SUBJECT: TS1 issues with TOU and Net Metering

Last fall we tried to setup and program a Landis+Gyr Axs4e meter with a Cellnet-Hunt TS1 endpoint for a Time of Use application as a test. After a number of attempts using different TS-1 configurations we have been unable to successfully use the TS1 endpoint to be able to correctly bill a TOU customer. These test revealed that the problem is due to limitations in the amount of data (or packet definition size) that can be successfully transmitted from the TS1 endpoint to Command Center and then transferred to the NISC I-Vue billing system.

We have been unable to successfully put two Kilowatt-hour readings (Rate A kWh and Rate B kWh) and two Demand (Rate A kW and Rate B kW) readings in the same packet without exceeding the TS1's allowable packet size. Two kWh and two kW readings is the minimum amount of data needed to correctly bill a TOU account with a single On-Peak and single Off-Peak time block.

We were able to overcome the data packet size limitations by using two meters each containing a TS1 endpoint for the account. One meter was configured to accrue the On-Peak data while the second meter was configured to accrue the Off-Peak data. This resulted in a very expensive

468 N Highway 89, Hatch, Utah 84735
Voice: (435)735-4288 Fax: (435)735-4312
E-mail: ctwitchell@garkaneenergy.com

and cumbersome installation because we had to have a second seriesed meter base installed and utilize two separate meters.

We also found that the I-Vue billing system would only accept one packet for each account being billed. I-Vue would only recognize and use the first data packet encountered for the specific account. The data from the second packet had to be located in the Command Center Data Base and manually entered into the billing system.

At your request, I have spent much of the past three weeks gathering information about Net and TOU metering with the TS1 system from the manufacturer (now Landis+Gyr formerly CellNet-Hunt) and other companies using the system. I have found a couple of different companies who are successfully using the TS1 system for residential and commercial Net and TOU metering. They seem to be using one of two methods to get around the packet size problem. They are either using two separate packets of data (one for On-Peak and one for Off-Peak) or are using a reduced data size (only reading 4 dials from a 5 dial meter).

Their TS1 Command Center to billing system interfaces seem to be able to manipulate the TS1 data packets that they receive from Command Center to input the data into their billing systems. The NISC I-Vue interface appears to take the data provided from Command Center as presented and is unable to adequately manipulate the input into the billing system.

As a result of the information gathered, I have spent the last 10 days trying different combinations of TS1 programming packet configurations and different billing setup combinations. I have been unable to find a packet configuration and billing setup combination which works successfully and reliably. The problems encountered all seem to associated with the data packet length issue and the inability to utilize multiple packets. These issues will hold irrespective of the specific meter used (i.e. L+G S4, GE KV2c, and Itron Centron meters with TS1 endpoint installations).

I have contacted Susan Blass with Landis+Gyr Energy Management Systems technical support. She has confirmed to me that with our current NISC I-Vue billing system we can program a TS1 endpoint to do TOU on residential customers, where we only need two registers of data (rate A kWh and rate B kWh). We will be unable to program a TS1 endpoint to get both kWh data (rate A kWh, rate B kWh) and demand data (rate A kW and rate B kW) for TOU metering for commercial customers.

She also informed me we will be unable to program a TS1 endpoint for Net metering on either residential or commercial customers where the rate for received kWh is a different rate than the rate for delivered kWh. This is due to limitations in the interface between the TS1 Command Center to I-Vue Systems. These limitations have been resolved in the TS2 to I-Vue Interface.

Based upon these test and information gained, the only viable solution for TOU and Net Metering is to manually read and bill the accounts or to upgrade to the TS2 system.

April 8, 2009

Carl Albrecht, CEO
Mike Avant, Engineering Manager
Stan Chappell, Finance Manager
Garkane Energy Cooperative, Inc.

Re: Smart Metering, Time-of-Use Rates, & Net Metering

Following is a description of my work on each of the above three topics:

Smart Metering (or Advanced Metering Infrastructure (AMI))

The Arizona Corporation Commission (ACC), in Decision No. 70696 in Docket No. E-01891A-08-0061, ordered Garkane to file a detailed benefit/cost analysis of its decision regarding implementation of Smart Metering by April 20, 2009.

I have identified two basic alternatives for Garkane:

1. Continue using the existing Landis & Gyr (L&G) TS1 metering system
    a. Use TS1 compatible meters to provide time-of-use (TOU) rates
    b. Offer TOU rates to residential customers (about 540 Arizona customers)
    c. Manually read & bill net metering customers
    d. No TOU for non-residential customers unless manually read & bill
2. Upgrade TS1 metering system to TS2
    a. Offer TOU rates to all customers (about 700 Arizona customers)
    b. Automated Net Metering for all customers
    c. Possible American Recovery & Reinvestment Act (ARRA) of 2009 grant for up to 50% of upgrade cost (per Mike Avant, L&G has a contractor that will assist with the grant application for a fee of $20,400)

I have used two different approaches for the AMI cost analysis (both models are contained in a single, multi-tabbed, spreadsheet named "AMI Cost Analysis-Garkane" and yield similar results):

1. I duplicated the spreadsheets used by ACC staff in Decision No. 70696 and made a few changes.
    a. Combined the original two spreadsheets into one
    b. Used incremental purchased power cost instead of average
    c. Took into account a possible demand surcharge for growth
    d. Used a Fixed Charge Rate based on Garkane's costs rather than Dixie Escalante's

e. Made the model interactive so different assumptions for % load shift and penetration can be used for "what if" analysis
f. Created two versions of the model, one for residential only and one for all customers except lighting (non-lighting)
g. Added calculation of the benefit/cost ratios for each alternative
h. Added a summary sheet showing the results of the alternatives including the monthly cost and benefit per TOU customer and the additional savings needed for a benefit/cost ratio of "1"
i. Included an alternative variation showing costs with a 50% ARRA grant based on information from Mike Avant
j. Used TS2 upgrade cost estimates provided by Mike Avant

2. I created a Revenue Requirement Impact model:
   a. Calculates the average incremental revenue requirement impact per TOU customer of implementing AMI (upgrade from TS1 to TS2)
   b. Where the incremental revenue requirement is equal to incremental expense plus the required TIER times the incremental interest cost associated with the new investment. The incremental expense equals O&M expense + property tax + depreciation less avoided purchased power demand costs.
   c. Calculates the revenue requirement impact for 25 years taking into account inflation
   d. Calculates the present value of the 25 years of revenue requirement impact. This present value is the amount of other company &/or societal benefits per TOU customer needed to offset the incremental cost of AMI
   e. Calculates the average monthly customer charge increase for TOU customers to cover the cost of implementing AMI
   f. Made the model interactive so results can be calculated for four variations of Alternative 2 (TS2 upgrade): Residential TOU only (with & without grant $) and All Non-Lighting TOU (with & without grant $)
   g. Assumptions for inflation, Long Term debt cost, TIER, and fixed charge rates can be easily changed in the Input Data section for "what if" analyses
   h. Used TS2 upgrade investment costs and benefits from the Benefit/Cost model
   i. Used 2008 meter O&M costs as a percent of meter plant, but model allows for this to be changed to the overall average O&M rate for all plant (which is much lower).

Discussion of Results of AMI Cost Analysis

The results of the Benefit/Cost model show all alternatives and variations have a benefit/cost ratio (BCR) less than "1", with the best alternative being Alternative 1 (keep TS1) with a BCR=0.84. This alternative was based on the individual meter incremental cost estimate of $511 used by the ACC staff. It is possible that a lower cost meter option might be available, making this option cost effective. Alternative 2 (upgrading to TS2) is high cost and even after expanding the TOU to all non-lighting rates (about 70 customers) and allowing for ARRA grant money, the BCR is only 0.45.

The ACC asks for consideration of all benefits including societal. I prepared a list of possible benefits (other than reduced purchased power demand costs) as a separate document, but did not develop related cost savings due to time constraints as well as the difficulty in estimating some of the savings. The Cooperative may be able to estimate the savings associated with the list of company benefits. The listed customer and societal benefits would be very difficult to quantify.

Both of the models show the amount of additional savings that would be needed to get the BCR=1. It may be easier to estimate if overall potential savings might equal or exceed those amounts, than to try and quantify each one.

The summary tab in the model shows the needed monthly customer charge increase for TOU customers to cover the AMI increased costs. Any additional benefits of AMI that can be quantified would help offset the cost of AMI and would reduce the needed increase in TOU customer charges. Customers would have to generate sufficient savings from shifting load off peak to recover this cost and still make it worth the trouble to switch to a TOU rate.

Some of the identified customer benefits may be of value to customers other than TOU. It might be reasonable to recover the cost of those benefits from all customers rather than in the TOU customer charge. The recovery of the cost of societal benefits is a more difficult issue as some of those benefits may accrue to people other than the Cooperative's customers.

Additional Comments about AMI's Potential for Cost Savings:

Since the ACC Order in this docket cited Sulphur Springs Valley Electric Cooperative's (SSVEC) experience with TOU rates, I read the cooperative's February 20, 2008 report to the ACC on TOU rates and talked with the manager who signed the report. I learned SSVEC has about 40,000 residential customers and only 17 participated in the TOU rate in 2007 (19 in 2005, 18 in 2006). Only 7 of the 17 actually saved money. Only 42 of about 8,000 general service customers participated in the TOU rate in 2007 (19 of those saved money).

SSVEC claimed $317,506 in savings in 2007 from avoided demand charges. Of that amount, $310,856 was achieved by 36 customers on Rate PT (35 were irrigators and the other a body shop that could work at night). That savings was for the cooperative as a whole. Only 25 of the 36 customers on the TOU rate actually saved money (one of the irrigators that did not, actually spent $24,652 more than if he had been on the regular rate).

One of the conclusions from this information is that the participation (penetration) rate is very small (0.05% and 0.5% for the residential and general service rates respectively). Rocky Mountain Power, in a June 29, 2007 letter to the Utah PSC, cites residential participation rates of less than 0.1% in TOU rates in Utah and less than 10% overall from an Itron industry study. The bottom line here is that the assumed 10% penetration rate in the Benefit/Cost and Revenue Requirement Impact studies may be optimistic.

In an August 26, 2005 ACC staff report on SSVEC's TOU rates, staff commented,

> There appears to be a lack of participation of residential customers for Schedule RT. Residential customers may not know that the rate schedule is available. SSVEC should market the time-of-use rate, possibly with an article in its newsletter. However, time-of-use rates are not for everyone. In fact, some of the customers who are on the rate did not save money in 2004. Marketing materials should explain clearly how the rate schedule works and who might benefit most from being on the rate. Staff recommends that SSVEC provide educational marketing of Schedule RT.

Marketing of TOU rates may be necessary to increase the participation rates.

Time-of-Use Rates

Garkane requested the development of optional Time-of-Use (TOU) rates for the Arizona rate schedules.

Deseret G&T (DGT) is the primary power source for Garkane and DGT incremental demand and energy prices are the same throughout the year. There is no seasonal difference in the incremental prices. Therefore, there is no need for a difference in seasonal TOU rates. The only reason for seasonal differences is any difference in the peak period hours. There is no difference in incremental energy prices between peak and off peak hours. Therefore, the only difference between peak period and off peak costs is in demand costs.

The first step in designing TOU rates is to determine the peak versus off peak time periods, including hours of the day, days of the week and how the peak period varied over the months of the year. At the January 26, 2009 meeting in St. George (LaDel Laub, Mike Avant, Stan Chappell, Colin Jack & myself), it was agreed to review the past five years of DGT monthly power bills. It was felt that five years would give a good look at patterns, but that more years might not be relevant for today.

I reviewed the monthly DGT power bills for the past five years and tabulated the hour, date, and day of the week of each month's system peak demand. I summarized the range of days of the week and hours of the day that the peak occurred for each month of the year for DGT, Garkane Energy and for Dixie Escalante. This data is included in a spreadsheet file named "System Peak Times." I observed similar patterns for the system peak times in the winter months of October through April and also for the summer months of May through September. This is the same split between summer and winter that Rocky Mountain Power uses for its Utah TOU rates.

I further observed that the system peaks throughout the year occurred on every day of the week over the five year study period. For example, DGT had summer peaks on all days except Friday, while Garkane had summer peaks on all days except Tuesday. DGT had winter peaks on all days except Saturday and Sunday, while Garkane had winter peaks on all days except Sunday. This would suggest Sunday could be off peak. However, I observed that Dixie had winter peaks on Sunday. My conclusion from this analysis is that to be conservative, all days of the week should be considered possible peak days for both summer and winter months.

The above mentioned tabulation of the range of peak hours for each month indicated that summer peaks occurred during the afternoon or evening. Winter peaks commonly occurred in the morning, with some in the evening. I obtained (with Mike Avant's help) DGT's typical daily load shape (over 24 hours) for the above winter months and for the summer months. This data is included in a spreadsheet named "DGT load shape". I graphed the hourly winter and summer load shapes to get a better feel for the shapes. I observed that the summer load shape is not peaky, but a rather smooth and slowly changing curve dipping only to a low point of 79% of the peak for a brief time. The winter load shape was different having two distinct peaks- one in the morning and another in the evening. However, the winter load shape between these two peaks only dipped to 90% of the peak.

In selecting the hours of the summer and winter peak periods, it is important to make sure that load shifted out of the peak period does not cause a new peak. This is remedied by selecting a peak period that includes shoulder periods that are fairly close to the peak. After analyzing the DGT load shapes, I concluded that a summer peak period of 10am to 11pm and a winter peak period of 6am to 11pm would be best.

The next step is to develop the costs needed for the TOU rate designs. I updated the Class Cost of Service Study using mostly calendar year 2008 data. Some data for the year ending August 31, 2008 was used given time constraints. I used the DGT load shape data to estimate the kilowatt-hour sales for each rate schedule for the peak periods. I expanded the summary cost of service by rate schedule results to breakout the demand costs by Coincident Peak, Primary and Secondary. I also expanded the average unit cost of service results to also breakout the demand costs into the same three components.

Cost data from the cost of service study, the AMI Cost Analysis and expected incremental demand costs were used to design individual rate elements for both TOU and non-TOU rates. For demand-metered rates, a single energy price was used based on the average cost of energy plus the primary and secondary demand costs. For residential, a peak and off peak energy price was used based on average costs (energy and demand) for those periods. For demand-metered rates, the peak demand price was based on the expected incremental demand cost adjusted for estimated demand losses. The proposed rates are included in two separate files named "2009 AZ Rate Proposal" (uses 8-31-08 billing units to calculate expected revenues) and "AZ TOU Prices"(which simply shows the TOU rate elements for each rate schedule as well as the peak period definition). I assume development of the actual rate schedule sheets can be done later. The objective is to design the rates to recover the appropriate costs while providing an incentive for customers to shift load off peak. The AMI cost analysis assumes the incentive is no more than the cost avoided.

Net Metering Rates

On October 23, 2008, the ACC, in Decision No. 70567, adopted Rules R14-2-2301 through R14-2-2308 regarding Net Metering. Based on an email forwarded to me(by Mike Avant), the Arizona Attorney General certified the Net Metering Rules on March 23, 2009 and sent them to the Secretary of State. The email indicated that the Rules would be effective on May 22, 2009 and Garkane would have 120 days or until September 19, 2009 to file its Net Metering Tariff with the ACC.

I reviewed Net Metering Rules R14-2-2301 through R14-2-2308. The key provisions related to billing are in R14-2-2306:

- Monthly billing under the customer's standard rate schedule
- Customer is billed for an excess of purchases (kWh) at the standard rate schedule rate
- Customer is credited (in kWh) for an excess of generation on the next bill
- TOU customer is credited on the next bill for excess kWh in the on or off peak period during which the kWh were generated
- Once each calendar year, the utility shall pay the customer for any balance of excess credit at the utility's avoided cost
- Avoided cost is defined in R14-2-2302 as "the incremental costs to an Electric Utility for electric energy or capacity or both which, but for the purchase from the Net Metering Facility, such utility would generate itself or purchase from another source."

The question then is what is Garkane's avoided cost for use in its Arizona Net Metering Tariff? As discussed previously under Time-of-Use Rates, Garkane's incremental cost of power is the incremental charges for energy or demand from DGT. I was able to talk with Phil Tice at DGT (with Stan Chappell's help) to better understand how WAPA rate changes affect Garkane's monthly power bill. I concluded that Garkane's current incremental cost of energy and capacity is $0.015 per kWh and $6.518 per kW. I learned a $2 per kW surcharge for growth is a potential increase in incremental capacity cost for the future.

Another consideration is energy losses. To sell a kWh to a secondary voltage customer, Garkane must purchase that kWh plus the related energy losses between the customer and the generator. The same is true for each kW of coincident demand. For Garkane's energy losses of about 10 percent, the avoided cost at the generator for a kWh at a secondary voltage customer is equal to 1.1 times the price per kWh at the generator. Garkane's avoided cost for a secondary voltage kWh is about $0.0165.

Avoided capacity costs occur when Garkane's incremental demand at the time of the DGT monthly peak is reduced. Capacity provided by a Net Metering Facility only causes Garkane to avoid a demand charge at DGT when the facility is generating excess power coincident with a DGT monthly peak.

The avoided capacity cost, like the avoided energy cost, must be adjusted for losses. In the cost of service study, demand losses are estimated at about 15 percent. This would result in avoided capacity costs for a secondary voltage customer of about $7.50 per coincident kW or about $9.80 with the possible $2 growth surcharge. The latter is the basis for the proposed $10 peak demand charge for TOU rates.

I have taken Garkane's Net Metering Rate 33 for Utah and modified it for a proposed Arizona Net Metering tariff consistent with the ACC Net Metering Rules.

Lowell Alt
Lalt677@msn.com
702-613-4086

GECOS08 TOU
4-6-09
Year End 12-31-08

COST-OF-SERVICE STUDY
GARKANE ENERGY
Year End 12-31-08
Allocation of Total Electric System
Between Arizona & Utah

CHECKSUM
OK

Avg 2007/2008 Rate Base

ALLOCATION FACTORS	AF	TOTAL	Arizona	Utah
Prod+Transmission+Distr Plant	1	1.0000	0.0843	0.9157
Distribution Plant	2	1.0000	0.0868	0.9132
Transmission Plant	3	1.0000	0.0733	0.9267
Distr Acct 362-station eq	4	1.0000	0.1409	0.8591
Distr Acct 364+365-OH lines	5	1.0000	0.1118	0.8882
Distr Acct 366+367-UG lines	6	1.0000	0.0226	0.9774
Distr Acct 368-line transformers	7	1.0000	0.0231	0.9769
Distr Acct 370-meters	8	1.0000	0.0256	0.9744
Distr Acct 371-inst on cust prem	9	1.0000	0.0278	0.9722
Distr Acct 582-587,592-597	10	1.0000	0.0880	0.9120
Customer Deposits	11	1.0000	0.1495	0.8505
Avg Utility Custs	12	1.0000	0.0603	0.9397
Production Plant	13	1.0000	0.0881	0.9119
Energy	14	1.0000	0.0881	0.9119
Distr Acct 373-St Lighting	15	1.0000	0.0780	0.9220
Transmission+Distribution Plant	16	1.0000	0.0838	0.9162
Purchased Power Kw + Kwh	17	1.0000	0.0798	0.9202
System 12CP Demand	18	1.0000	0.0733	0.9267
Distr Acct 364-Poles,towers, fixt	19	1.0000	0.0943	0.9057
O&M-Power Prod Exp (calc)	20	1.0000	0.0791	0.9209
Total revenues	21	1.0000	0.0877	0.9123
Total Net Plant	22	1.0000	0.0696	0.9304

ALLOCATE RATE BASE	AF	avg 07/08 TOTAL	Arizona	Utah	checksum
PRODUCTION PLANT	14	6,537,753	576,169	5,961,584	0
TRANSMISSION PLANT	18	11,585,950	848,869	10,737,081	0
DISTRIBUTION PLANT					
360-Land	DIR	343,334	40,889	302,446	0
362-Station equipment	DIR	6,908,157	973,449	5,934,708	0
364-Poles,towers & fixtures	DIR	7,313,603	689,485	6,624,118	0
365-Overhead conductors	DIR	8,971,473	1,131,441	7,840,032	0
366-Undergrd conduit	DIR	131,728	7,227	124,501	0
367-Undergrd conductors	DIR	2,060,441	42,309	2,018,132	0
368-Line transformers	DIR	9,101,530	210,101	8,891,429	0
369-Services	DIR	2,393,408	277,242	2,116,166	0
370-Meters	DIR	2,160,146	55,265	2,104,881	0
371-Install on cust premises	DIR	109,422	3,038	106,384	0
373-Street lighting	DIR	103,895	8,105	95,790	0
Total Distribution Plant		39,597,134	3,438,549	36,158,585	0
GENERAL PLANT	1	10,464,129	881,713	9,582,416	0
TOTAL PLANT IN SERVICE		68,184,965	5,745,299	62,439,666	0
CWIP	DIR	4,156,893	0	4,156,893	0
Materials & Supplies-electric	1	3,262,689	274,916	2,987,773	0
Prepayments	1	63,103	5,317	57,785	0
Cash Working Capital *		1,131,218	90,987	1,040,231	0
Subtotal		8,613,902	371,219	8,242,683	0
LESS Accumulated depreciation					
Production	13	3,148,315	277,459	2,870,856	0
Transmission	3	6,079,847	445,453	5,634,394	0
Distribution	DIR	12,205,779	1,692,787	10,512,992	0
General	1	5,075,577	427,671	4,647,906	0
Subtotal		26,509,517	2,843,370	23,666,147	0
LESS Cust impact fees	DIR	530,636	0	530,636	0
LESS Cust deposits	DIR	369,686	55,268	314,418	0
TOTAL RATE BASE		49,389,029	3,217,881	46,171,148	0

* CWC = 1/24 of prod exp (including purch power) + 45 days of other exp (excl deprec)

ATTACHMENT3

ALLOCATE EXPENSES	AF	TOTAL	Arizona	Utah	
POWER PRODUCTION					
Hydro O&M	13	286,390	25,239	261,151	0
Other O&M	13	35,835	3,158	32,677	0
Subtotal		322,225	28,398	293,827	0
Purchased Power-KW	18	2,639,624	193,398	2,446,226	0
Purchased Power-KWH	14	2,084,239	183,683	1,900,556	0
Purchased Power-other	17	485,400	38,747	446,653	0
556-Syst contrl & ld dispatch	17	22,639	1,807	20,832	0
Subtotal		5,231,902	417,635	4,814,267	0
TRANSMISSION O&M	3	734,739	53,832	680,907	0
DISTRIBUTION OPER					0
580-Supervision	10	25,304	2,226	23,078	0
581-Load dispatching	10	27,464	2,416	25,048	0
582-Station	4	23,370	3,293	20,077	0
583-Overhead lines	5	88,536	9,900	78,636	0
584-Undergrd lines	6	6,262	141	6,121	0
585-Street Lights	15	4,113	321	3,792	0
586-Meters	8	185,018	4,733	180,285	0
587-Cust installations	12	5,907	356	5,551	0
588-Misc	10	221,816	19,512	202,304	0
589-Rents	10	210	18	192	0
Subtotal		588,000	42,917	545,083	0
DISTRIBUTION MAINT					0
590-Maint suprv & engr	10	25,594	2,251	23,343	0
592-Station equipment	4	158,644	22,355	136,289	0
593-Overhead lines	5	991,551	110,871	880,680	0
594-Undergrd lines	6	161,868	3,658	158,210	0
595-Line transformers	7	57,865	1,336	56,529	0
596-Maint of St Lights	15	16,282	1,270	15,012	0
597-Meters	8	140,189	3,587	136,602	0
598-Misc	9	13,249	368	12,881	0
Subtotal		1,565,242	145,695	1,419,547	0
CUSTOMER EXPENSES					0
901-Supervision-accts	12	29,913	1,804	28,109	0
902-Meter reading	12	206,114	12,427	193,687	0
903-Records & collection	12	397,198	23,949	373,249	0
904-Uncollectibles	12	0	0	0	0
908-Cust Assistance	12	79,524	4,795	74,729	0
909-Info & instruc advertising	12	22,976	1,385	21,591	0
910-Misc cust svc & info	12	2,144	129	2,015	0
912-Demonstrating & selling	12	16,489	994	15,495	0
913-Advertising ADM	12	0	0	0	0
Subtotal		754,358	45,483	708,875	0
ADMINISTRATIVE & GENERAL					0
920-Admin & gen salaries	1	492,217	41,474	450,743	0
921-Office supplies & expenses	1	234,902	19,793	215,109	0
923-Outside services	1	105,208	8,865	96,343	0
924-Property insurance	1	152,218	12,826	139,392	0
925-Injuries & damages	1	137,466	11,583	125,883	0
926-Employee pensions/benefits	20	1,193,689	94,361	1,099,328	0
928-Regulatory expenses	21	20,237	1,776	18,461	0
930-Misc general expenses	20	817,052	64,588	752,464	0
931-Rents	1	0	0	0	0
932-Maint of general plant	1	137,072	11,550	125,522	0
Subtotal		3,290,061	266,816	3,023,245	0
DEPRECIATION EXPENSE					0
Production	13	148,232	13,064	135,168	0
Transmission	3	295,703	21,665	274,038	0
Distribution	DIR	1,200,834	133,124	1,067,710	0
General	1	497,151	41,890	455,261	0
Subtotal		2,141,920	209,744	1,932,176	0
Taxes-Property-Electric Utility	1	274,534	23,132	251,402	0
Taxes-other	14	69,763	6,148	63,615	0
Interest on cust deposits	11	21,645	3,236	18,409	0
TOTAL EXPENSES		14,994,389	1,243,036	13,751,353	0
					0
REVENUES-RATES *	DIR	15,598,139	1,377,561	14,220,578	0
REVENUES-CREDITS					0
450-Penalties	DIR	20,579	1,873	18,706	0
451-Conn,Disc & ret ck fees	DIR	39,718	3,614	36,104	0
454-Rent fr elec prop	DIR	28,275	2,573	25,702	0
456-other electric revenue	1	76,154	6,417	69,737	0
456.01-Wheeling revenue	3	616,153	45,144	571,009	0
Subtotal		780,879	59,621	721,258	0
REVENUES-TOTAL		16,379,018	1,437,182	14,941,836	0
					0
% RETURN ON RATE BASE		2.80%	6.03%	2.58%	0

* Utah Rate Revenues - 8-31-08 rate increase annualized

					0
Interest Expense		TOTAL	Arizona	Utah	
Existing debt	22	1,748,000	121,716	1,626,284	0
With $5mill new debt @5.7%	22	2,033,000	141,561	1,891,439	0
With $7mill new debt @5.7%	22	2,147,000	149,499	1,997,501	0
					0
TIER					
With existing debt		0.79	1.60	0.73	
With $5mill new debt		0.68	1.37	0.63	
With $7mill new debt		0.64	1.30	0.60	
Target Rate of Return for TIER=1.5					
With existing debt		**5.31%**	**5.67%**	**5.28%**	
With $5mill new debt		6.17%	6.60%	6.14%	
With $7mill new debt		6.52%	6.97%	6.49%	

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Summary Results

With existing debt

Utah Cost of Service Study
Garkane Energy Cooperative
Year End 12-31-08

Rate Schedule	Earned % Return on Rate Base	ROR Index No.	% Rate Incr Required for ROR of *5.28%*
Residential 21	-1.46%	-0.57	27.35%
Irrigation 24	-1.75%	-0.68	30.64%
Small Commercial 25	6.46%	2.50	-3.17%
Lighting 27	16.09%	6.24	-25.15%
Commercial 28	3.02%	1.17	6.91%
Municipal 29	3.91%	1.52	4.74%
Federal Gov 32	12.03%	4.67	-12.18%
Ex Lg Power 15	22.79%	8.84	-29.43%
Kanab-Res 21	1.28%	0.50	14.03%
Kanab-GS1 25	8.89%	3.45	-9.22%
Kanab-St Lights 27	15.12%	5.86	-30.09%
Kanab-GS2 28	13.32%	5.17	-18.13%
Kanab-Fed Gov 32	-41.25%	-16.00	100.04%
TOTAL UTAH	2.58%	1.00	8.78%

Arizona Cost of Service Study
Garkane Energy Cooperative
Year End 12-31-08

Rate Schedule	Earned % Return on Rate Base	ROR Index No.	% Rate Increase Required for ROR of 5.67%
Residential 01	0.45%	0.07	14.46%
Small Commercial 05	10.20%	1.69	-9.40%
Public Authorities 06	9.42%	1.56	-8.12%
Large Power 08	18.81%	3.12	-22.52%
Irrigation 04	-5.84%	-0.97	43.91%
Street & Security Lights 07	1.26%	0.21	10.39%
TOTAL ARIZONA	6.03%	1.00	-0.84%

Year End 12-31-08 With Utah/Kanab Consolidated

Rate Schedule	**% Rate Incr Required for ROR of 5.28%**
Residential 21	25.32%
Irrigation 24	30.64%
Small Commercial 25	-5.12%
Lighting 27	-26.38%
Commercial 28	1.74%
Municipal 29	4.74%
Federal Gov 32	1.64%
Ex Lg Power 15	-29.43%
TOTAL UTAH	8.78%

With existing debt

CHECKSUM
OK

COST-OF-SERVICE STUDY
GARKANE ENERGY- Utah
Year End 12-31-08

** INPUT VALUES

1.1569705 = Demand Loss Factor (sec) **
1.1099 = Energy Loss Factor (sec)

1. Residential 21	L#	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	TOTAL	
KWH @ Meter **	1	9,424,375	9,265,416	6,848,273	5,932,588	5,114,243	4,393,761	4,248,240	4,903,944	4,292,043	4,370,937	5,061,324	6,956,014	70,811,158	
KWH @ Input	2	10,459,919	10,283,494	7,600,757	6,584,457	5,676,193	4,876,545	4,715,034	5,442,786	4,763,650	4,851,213	5,617,459	7,720,336	78,591,842	
Load Factor (PU) **	3	0.1610	0.1480	0.1430	0.1350	0.1300	0.1400	0.1400	0.1440	0.1370	0.1300	0.1300	0.1300	0.139	avg
Max Cust Demand (KW) calc	4	78,678	93,161	64,368	61,035	52,877	43,589	40,786	45,773	43,512	45,192	54,074	71,919	694,964	
Schedule Coincidence Factor	5	0.317	0.240	0.327	0.240	0.300	0.252	0.250	0.255	0.250	0.310	0.252	0.335	0.277	avg
Sched PK @ Meter (KW)	6	24,941	22,359	21,048	14,648	15,863	10,984	10,196	11,672	10,878	14,009	13,627	24,093	194,319	
Sched PK @ Input (KW)	7	28,856	25,868	24,352	16,948	18,353	12,709	11,797	13,504	12,586	16,208	15,766	27,875	224,822	
System Coincidence Factor	8	0.760	0.717	0.607	0.763	0.576	0.600	0.620	0.650	0.580	0.753	0.500	0.745	0.656	avg
Coincident PK @ Input (KW)	9	21,931	18,548	14,782	12,931	10,571	7,625	7,314	8,778	7,300	12,205	7,883	20,767	150,634	

1.1570 = Demand Loss Factor (sec)
1.1099 = Energy Loss Factor (sec)

2. Irrigation 24	L#	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	TOTAL	
KWH @ Meter **	1	16,718	14,942	19,570	28,908	152,974	815,461	732,908	798,461	658,445	483,900	78,228	32,829	3,833,344	
KWH @ Input	2	18,555	16,584	21,720	32,084	169,783	905,063	813,439	886,195	730,795	537,071	86,824	36,436	4,254,549	
Load Factor (PU)calc'd	3	0.3091	0.3146	0.2658	0.1334	0.2694	0.5920	0.4935	0.5336	0.4720	0.4041	0.3449	0.3056	0.370	avg
Max Cust Demand (KW)**	4	73	71	99	301	763	1,913	1,996	2,011	1,937	1,609	315	144	11,233	
Schedule Coincidence Factor	5	0.408	0.000	0.067	0.999	0.710	0.883	0.790	0.891	1.000	0.061	0.161	0.323	0.524	avg
Sched PK @ Meter (KW)	6	30	0	7	301	542	1689	1577	1792	1937	98	51	47	8,070	
Sched PK @ Input (KW)	7	34	0	8	348	627	1955	1824	2073	2242	114	59	54	9,337	
System Coincidence Factor	8	0.242	0.000	0.833	0.041	0.780	0.796	0.763	0.343	0.332	0.799	0.813	0.267	0.501	avg
Coincident PK @ Input (KW)	9	8	0	6	14	489	1556	1392	711	744	91	48	14	5,074	

1.1570 = Demand Loss Factor (sec)
1.1099 = Energy Loss Factor (sec)

3. Small Commercial GS1 25	L#	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	TOTAL	
KWH @ Meter **	1	2,004,197	2,090,128	1,711,244	1,714,003	1,853,462	1,814,965	1,986,401	2,224,262	1,892,673	1,740,600	1,621,219	1,661,761	22,314,915	
KWH @ Input	2	2,224,417	2,319,790	1,899,274	1,902,337	2,057,119	2,014,392	2,204,665	2,468,662	2,100,639	1,931,856	1,799,357	1,844,354	24,766,863	
Load Factor (PU)calc'd	3	0.3686	0.4301	0.3224	0.3084	0.3037	0.2999	0.3107	0.3544	0.3147	0.2700	0.2804	0.2890	0.321	avg
Max Cust Demand (KW)**	4	7,308	7,231	7,133	7,719	8,202	8,404	8,592	8,437	8,354	8,666	8,031	7,730	95,808	
Schedule Coincidence Factor	5	0.506	0.528	0.583	0.571	0.510	0.527	0.672	0.685	0.476	0.542	0.702	0.440	0.562	avg
Sched PK @ Meter (KW)	6	3,698	3,818	4,159	4,408	4,183	4,429	5,774	5,779	3,977	4,697	5,638	3,401	53,960	
Sched PK @ Input (KW)	7	4,278	4,417	4,811	5,100	4,840	5,124	6,680	6,686	4,601	5,434	6,523	3,935	62,430	
System Coincidence Factor	8	0.700	0.771	0.900	0.820	1.000	0.890	0.865	0.820	0.700	0.744	0.858	0.479	0.796	avg
Coincident PK @ Input (KW)	9	2,995	3,406	4,330	4,182	4,840	4,561	5,778	5,483	3,221	4,043	5,597	1,885	50,319	

1.1570 = Demand Loss Factor (sec)
1.1099 = Energy Loss Factor (sec)

4. Street & Security Lights 27	L#	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	TOTAL	
KWH @ Meter **	1	40,280	40,280	40,280	40,280	40,280	40,280	40,280	40,280	40,280	40,280	40,280	40,280	483,360	
KWH @ Input	2	44,706	44,706	44,706	44,706	44,706	44,706	44,706	44,706	44,706	44,706	44,706	44,706	536,471	
Load Factor (PU) calc	3	0.4595	0.5088	0.4595	0.4748	0.4595	0.4748	0.4595	0.4595	0.4748	0.4595	0.4748	0.4595	0.469	avg
Max Cust Demand (KW) **	4	118	118	118	118	118	118	118	118	118	118	118	118	1,414	
Schedule Coincidence Factor	5	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000		
Sched PK @ Meter (KW)	6	118	118	118	118	118	118	118	118	118	118	118	118	1,414	
Sched PK @ Input (KW)	7	136	136	136	136	136	136	136	136	136	136	136	136	1,636	
System Coincidence Factor	8	1.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	1.000		
Coincident PK @ Input (KW)	9	136	0	0	0	0	0	0	0	0	0	0	136	273	

1.1570 = Demand Loss Factor (sec)
1.1099 = Energy Loss Factor (sec)

5. Commercial GS2 28	L#	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	TOTAL	
KWH @ Meter **	1	2,304,199	2,486,832	1,942,311	1,882,179	2,179,220	1,722,848	1,780,710	2,025,066	1,752,822	1,745,989	1,889,119	1,679,771	23,391,066	
KWH @ Input	2	2,557,383	2,760,083	2,155,731	2,088,992	2,418,671	1,912,153	1,976,373	2,247,579	1,945,421	1,937,837	2,096,694	1,864,343	25,961,261	
Load Factor (PU) calc	3	0.4293	0.5028	0.3821	0.3574	0.3819	0.3286	0.3677	0.4177	0.3540	0.3033	0.3448	0.3047	0.373	avg
Max Cust Demand (KW) **	4	7,214	7,361	6,833	7,315	7,669	7,282	6,510	6,517	6,877	7,737	7,610	7,410	86,333	
Schedule Coincidence Factor	5	0.921	0.794	0.900	0.780	0.700	0.733	0.706	0.700	0.760	0.772	0.816	0.887	0.789	avg
Sched PK @ Meter (KW)	6	6644	5844	6149	5705	5368	5338	4596	4562	5226	5973	6209	6573	68,188	
Sched PK @ Input (KW)	7	7687	6762	7115	6601	6211	6176	5317	5278	6047	6911	7184	7604	78,892	
System Coincidence Factor	8	0.963	0.862	0.957	0.902	0.780	0.976	0.910	0.875	0.885	0.929	0.900	0.900	0.903	avg
Coincident PK @ Input (KW)	9	7403	5829	6809	5954	4844	6028	4839	4618	5351	6420	6466	6844	71,404	
						0									

1.1570 = Demand Loss Factor (sec)
1.1099 = Energy Loss Factor (sec)

6. Municipal Culinary 29	L#	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	TOTAL	
KWH @ Meter **	1	21,723	22,340	24,419	29,714	45,228	54,892	67,173	69,390	54,167	45,720	29,448	20,131	484,345	
KWH @ Input	2	24,110	24,795	27,102	32,979	50,198	60,923	74,554	77,015	60,119	50,744	32,684	22,343	537,565	
Load Factor (PU)calc'd	3	0.2403	0.2294	0.1510	0.2588	0.2916	0.4195	0.3631	0.4753	0.3900	0.2576	0.1456	0.0926	0.276	avg
Max Cust Demand (KW) **	4	122	145	217	159	208	182	249	196	193	239	281	292	2,483	
Schedule Coincidence Factor	5	0.550	0.521	0.530	0.565	0.390	0.580	0.610	0.590	0.760	0.600	0.490	0.790	0.581	avg
Sched PK @ Meter (KW)	6	67	76	115	90	81	105	152	116	147	143	138	231	1,460	
Sched PK @ Input (KW)	7	77	87	133	104	94	122	175	134	170	166	159	267	1,689	
System Coincidence Factor	8	0.569	0.771	0.893	0.820	0.748	0.890	0.807	0.817	0.700	0.800	0.600	0.600	0.751	avg
Coincident PK @ Input (KW)	9	44	67	119	85	70	109	142	109	119	133	96	160	1,253	

1.1570 = Demand Loss Factor (sec)
1.1099 = Energy Loss Factor (sec)

7. Federal Gov. GS3 32	L#	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	TOTAL	
KWH @ Meter **	1	157,060	181,579	122,758	134,558	184,663	157,127	144,242	162,405	143,327	122,123	122,063	127,696	1,759,601	
KWH @ Input	2	174,318	201,531	136,247	149,343	204,954	174,392	160,091	180,250	159,076	135,542	135,475	141,727	1,952,945	
Load Factor (PU)calc'd	3	0.4564	0.5677	0.3407	0.3598	0.4246	0.3424	0.3123	0.3767	0.3569	0.2922	0.3707	0.3077	0.376	avg
Max Cust Demand (KW)**	4	463	476	484	519	585	637	621	579	558	562	457	558	6,499	
Schedule Coincidence Factor	5	0.504	0.521	0.580	0.565	0.504	0.520	0.663	0.677	0.482	0.600	0.700	0.700	0.585	avg
Sched PK @ Meter (KW)	6	233	248	281	293	295	331	412	392	269	337	320	390	3,802	
Sched PK @ Input (KW)	7	270	287	325	340	341	383	476	454	311	390	370	452	4,399	
System Coincidence Factor	8	0.800	0.771	0.900	0.820	1.000	0.890	0.865	0.880	0.930	0.744	0.800	0.800	0.850	avg
Coincident PK @ Input (KW)	9	216	221	292	278	341	341	412	399	289	290	296	361	3,738	

1.12243699 = Demand Loss Factor (pri)
1.07692 = Energy Loss Factor (pri)

8. Extra Large Power 15	L#	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	TOTAL	
KWH @ Meter **	1	2,236,000	1,922,000	2,078,000	1,818,000	2,007,000	1,801,000	2,213,000	1,807,000	2,036,000	2,000,000	1,607,000	2,133,000	23,658,000	
KWH @ Input	2	2,407,983	2,069,832	2,237,831	1,957,832	2,161,369	1,939,525	2,383,214	1,945,986	2,192,600	2,153,831	1,730,603	2,297,061	25,477,668	
Load Factor (PU)calc'd	3	1.0673	1.0211	0.9926	0.8954	0.9614	0.8836	1.0589	0.8656	1.0175	0.9617	0.8008	1.0253	0.963	avg
Max Cust Demand (KW)**	4	2,816	2,801	2,814	2,820	2,806	2,831	2,809	2,806	2,779	2,795	2,787	2,796	33,660	
Schedule Coincidence Factor	5	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000		
Sched PK @ Meter (KW)	6	2816	2801	2814	2820	2806	2831	2809	2806	2779	2795	2787	2796	33,660	
Sched PK @ Input (KW)	7	3161	3144	3158	3165	3150	3177	3153	3150	3120	3137	3128	3138	37,781	
System Coincidence Factor	8	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000		
Coincident PK @ Input (KW)	9	3161	3144	3158	3165	3150	3177	3153	3150	3120	3137	3128	3138	37,781	

1.156971 = Demand Loss Factor (sec)

1.1099 = Energy Loss Factor (sec)

9. Kanab Residential 21	L#	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	TOTAL	
		0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000		
KWH @ Meter **	1	1,669,912	1,629,871	1,042,828	968,261	794,855	772,774	997,897	1,119,149	869,758	785,581	879,153	1,139,524	12,669,563	
KWH @ Input	2	1,853,401	1,808,960	1,157,413	1,074,653	882,193	857,686	1,107,545	1,242,120	965,326	871,900	975,754	1,264,734	14,061,686	
Load Factor (PU) **	3	0.2150	0.2050	0.1790	0.1510	0.1330	0.1410	0.1230	0.1250	0.1130	0.1200	0.1140	0.1650	0.149	avg
Max Cust Demand (KW) calc	4	10,440	11,831	7,830	8,906	8,033	7,612	10,905	12,034	10,690	8,799	10,711	9,283	117,073	
Schedule Coincidence Factor	5	0.358	0.364	0.314	0.261	0.255	0.263	0.298	0.260	0.235	0.300	0.316	0.301	0.294	avg
Sched PK @ Meter (KW)	6	3737	4307	2459	2324	2048	2002	3250	3129	2512	2640	3385	2794	34,586	
Sched PK @ Input (KW)	7	4195	4834	2760	2609	2299	2247	3647	3512	2820	2963	3799	3136	38,821	
System Coincidence Factor	8	0.747	0.804	0.559	0.559	0.541	0.534	0.556	0.594	0.425	0.600	0.702	0.734	0.613	avg
Coincident PK @ Input (KW)	9	3134	3886	1543	1458	1244	1200	2028	2086	1198	1778	2667	2302	24,524	

1.156971 = Demand Loss Factor (sec)
1.1099 = Energy Loss Factor (sec)

10. Kanab GS1 25	L#	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	TOTAL	
KWH @ Meter **	1	1,067,625	1,055,524	740,565	787,528	821,110	874,983	1,074,132	1,185,348	896,003	819,271	794,515	780,783	10,897,387	
KWH @ Input	2	1,184,935	1,171,504	821,938	874,061	911,333	971,126	1,192,157	1,315,593	994,455	909,292	881,816	866,575	12,094,785	
Load Factor (PU)calc'd	3	0.3944	0.4519	0.2791	0.3016	0.2864	0.3140	0.3544	0.4044	0.3201	0.3107	0.3194	0.2867	0.335	avg
Max Cust Demand (KW)**	4	3,638	3,475	3,567	3,626	3,854	3,870	4,073	3,940	3,888	3,544	3,454	3,660	44,590	
Schedule Coincidence Factor	5	0.506	0.528	0.583	0.571	0.510	0.527	0.672	0.685	0.476	0.542	0.702	0.440		
Sched PK @ Meter (KW)	6	1841	1835	2079	2071	1966	2039	2737	2699	1851	1921	2425	1610	25,074	
Sched PK @ Input (KW)	7	2066	2060	2334	2324	2206	2289	3072	3029	2077	2156	2722	1808	28,144	
System Coincidence Factor	8	0.700	0.771	0.900	0.820	1.000	0.890	0.865	0.820	0.700	0.744	0.858	0.479		
Coincident PK @ Input (KW)	9	1446	1588	2101	1906	2206	2037	2658	2484	1454	1604	2335	866	22,685	

1.156971 = Demand Loss Factor (sec)
1.1099 = Energy Loss Factor (sec)

11. Kanab St/Sec Lights 27	L#	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	TOTAL	
KWH @ Meter **	1	17,560	17,560	17,560	17,560	17,560	17,560	17,560	17,560	17,560	17,560	17,560	17,560	210,720	
KWH @ Input	2	19,489	19,489	19,489	19,489	19,489	19,489	19,489	19,489	19,489	19,489	19,489	19,489	233,874	
Load Factor (PU)calc'd	3	0.4595	0.5088	0.4595	0.4748	0.4595	0.4748	0.4595	0.4595	0.4748	0.4595	0.4748	0.4595	0.469	avg
Max Cust Demand (KW)**	4	51	51	51	51	51	51	51	51	51	51	51	51	616	
Schedule Coincidence Factor	5	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000		
Sched PK @ Meter (KW)	6	51	51	51	51	51	51	51	51	51	51	51	51	616	
Sched PK @ Input (KW)	7	58	58	58	58	58	58	58	58	58	58	58	58	692	
System Coincidence Factor	8	1.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	1.000		
Coincident PK @ Input (KW)	9	58	0	0	0	0	0	0	0	0	0	0	58	115	

1.156971 = Demand Loss Factor (sec)
1.1099 = Energy Loss Factor (sec)

12. Kanab GS2 28	L#	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	TOTAL	
KWH @ Meter **	1	530,060	542,820	404,260	472,820	484,880	486,540	600,780	676,740	555,820	498,240	493,180	458,480	6,204,620	
KWH @ Input	2	588,303	584,571	435,354	509,187	522,175	523,962	646,989	728,792	598,571	536,562	531,113	493,744	6,699,325	
Load Factor (PU)calc'd	3	0.5333	0.6185	0.3978	0.5024	0.4500	0.4430	0.5052	0.5734	0.4824	0.4917	0.5352	0.4528	0.499	avg
Max Cust Demand (KW)**	4	1,336	1,306	1,366	1,307	1,448	1,525	1,598	1,586	1,600	1,362	1,280	1,361	17,077	
Schedule Coincidence Factor	5	0.921	0.794	0.900	0.780	0.700	0.733	0.706	0.700	0.760	0.772	0.816	0.887		
Sched PK @ Meter (KW)	6	1230	1037	1229	1019	1014	1118	1128	1110	1216	1052	1044	1207	13,407	
Sched PK @ Input (KW)	7	1381	1164	1380	1144	1138	1255	1267	1246	1365	1180	1172	1355	15,048	
System Coincidence Factor	8	0.963	0.862	0.957	0.902	0.780	0.976	0.910	0.875	0.885	0.929	0.900	0.900		
Coincident PK @ Input (KW)	9	1330	1003	1321	1032	888	1225	1153	1091	1208	1096	1055	1220	13,621	

1.156971 = Demand Loss Factor (sec)
1.1099 = Energy Loss Factor (sec)

13. Kanab Fed Gov GS3 32	L#	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	TOTAL	
KWH @ Meter **	1	22,898	22,763	16,081	16,433	18,362	18,186	24,254	27,168	19,485	17,519	16,936	15,716	235,801	
KWH @ Input	2	25,414	25,264	17,848	18,239	20,380	20,184	26,919	30,153	21,626	19,444	18,797	17,443	261,711	
Load Factor (PU)calc'd	3	0.2798	0.3135	0.2018	0.2112	0.3045	0.2975	0.3713	0.4253	0.3262	0.3698	0.3533	0.1904	0.304	avg
Max Cust Demand (KW)**	4	110	108	107	108	81	85	88	86	83	64	67	111	1,097	
Schedule Coincidence Factor	5	0.504	0.521	0.570	0.565	0.504	0.520	0.663	0.677	0.482	0.600	0.700	0.700		
Sched PK @ Meter (KW)	6	55	56	61	61	41	44	58	58	40	38	47	78	638	
Sched PK @ Input (KW)	7	62	63	69	69	46	50	65	65	45	43	52	87	716	
System Coincidence Factor	8	0.800	0.771	0.900	0.820	1.000	0.890	0.865	0.880	0.930	0.744	0.800	0.800		
Coincident PK @ Input (KW)	9	50	49	62	56	46	44	57	57	42	32	42	70	605	

1.156971 = Demand Loss Factor (sec)
1.1099 = Energy Loss Factor (sec)

14. Company Use	L#	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	TOTAL	
KWH @ Meter **	1	129,967	118,534	73,387	61,437	73,167	134,644	47,693	36,748	49,716	48,022	56,900	54,922	885,137	
KWH @ Input	2	144,248	131,558	81,451	68,188	81,207	149,439	52,933	40,786	55,179	53,299	63,152	60,957	982,395	
Load Factor (PU) **	3	0.2840	0.2270	0.2510	0.2140	0.1710	0.1800	0.2430	0.2720	0.2040	0.2170	0.2020	0.1950	0.222	avg
Max Cust Demand (KW) (calc)	4	615	777	393	399	575	1,039	264	182	338	297	391	379	5,649	
Schedule Coincidence Factor	5	0.502	0.521	0.508	0.565	0.504	0.520	0.663	0.677	0.482	0.538	0.443	0.439	0.530	avg
Sched PK @ Meter (KW)	6	309	405	200	225	290	540	175	123	163	160	173	166	2,929	
Sched PK @ Input (KW)	7	347	454	224	253	325	606	196	138	183	180	195	187	3,288	
System Coincidence Factor	8	0.569	0.771	0.893	0.820	1.000	0.890	0.865	0.880	0.930	0.744	0.299	0.251	0.743	avg
Coincident PK @ Input (KW)	9	197	350	200	207	325	540	170	121	170	134	58	47	2,520	

SUMMARY Est Load-UT w/o K	TOTAL	Residential21	Irrigation 24	Sm Comm 25	St/Sec Lts27	Comm 28	Municipal 29	Fed Gov 32	ExLgPwr15
MWH @ Meter	146,735,789	70,811,158	3,833,344	22,314,915	483,360	23,391,066	484,345	1,759,601	23,658,000
MWH @ Input	162,079,164	78,591,842	4,254,549	24,766,863	536,471	25,961,261	537,565	1,952,945	25,477,668
Max Cust Dem-NCP mo (kw)	115,453	93,161	2,011	8,666	118	7,737	292	637	2,831
Distr In transf design CF *		0.89	1.00	1.00	1.00	1.00	1.00	1.00	
MCD (kw) X DCF	102,375	82,913	2,011	8,666	118	7,737	292	637	
Sched Pk Month @ Input (kw)	49,528	28,856	2,242	6,686	136	7,687	267	476	3,177
Sys 12CP @ Input (KW)	320,476	150,634	5,074	50,319	273	71,404	1,253	3,738	37,781
	176,953,880								

SUMMARY Est Loads-Kanab	TOTAL-Kanab	K-Res 21	K-GS1 25	K-St Lts 27	K-GS2 28	K-Fed G 32
MWH @ Meter	30,218,091	12,669,563	10,897,387	210,720	6,204,620	235,801
MWH @ Input	33,351,380	14,061,686	12,094,785	233,874	6,699,325	261,711
Max Cust Dem-NCP mo (kw)	17,870	12,034	4,073	51	1,600	111
Distr In transf design CF *		0.89	1.00	1.00	1.00	1.00
MCD (kw) X DCF	16,546	10,710	4,073	51	1,600	111
Sched Pk Month @ Input (kw)	9,432	4,834	3,072	58	1,381	87
Sys 12CP @ Input (KW)	61,552	24,524	22,685	115	13,621	605

* based on avg of 1.5 res custs per line transf, a winter design coincidence factor of 0.89 accounts for diversity in sizing transf

SUMMARY Est Loads-Co. Use	TOTAL-Co.Use
MWH @ Meter	885,137
MWH @ Input	982,395
Max Cust Dem-NCP mo (kw)	1,039
Distr In transf design CF *	1.00
MCD (kw) X DCF	1,039
Sched Pk Month @ Input (kw)	606
Sys 12CP @ Input (KW)	2,520

Monthly CP Est vs Actual	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	TOTAL
Estimated UT CP Kw @input =	41,911	37,741	34,523	31,063	28,689	27,903	28,924	28,966	24,046	30,829	29,612	37,821	382,027
Estimated AZ CP Kw @input =	2,784	2,955	1,998	2,037	2,165	2,326	2,856	2,750	2,209	2,876	2,966	2,282	30,203
Est Co.Use CP Kw @input =	197	350	200	207	325	540	170	121	170	134	58	47	2,520
Est Tot Syst CP Kw @input =	44,892	41,047	36,721	33,307	31,179	30,768	31,950	31,838	26,425	33,838	32,637	40,150	414,750
Actual System CP KW @ Input =	44,685	41,040	36,719	33,515	31,186	30,751	31,950	31,846	26,438	34,036	32,644	40,148	414,958
Estimated - Actual (kw) =	207	7	2	-208	-7	17	0	-8	-13	-198	-7	2	-208

Actual Total System kwh Losses =	20,270,344	
Estimated Co. Use Kwh losses =	97,258	
Estimated UT Kwh losses =	18,476,665	
Estimated AZ Kwh losses =	1,696,388	
Est Tot System Kwh Losses =	20,270,310	
Estimated - Actual Kwh losses =	-34	(should = 0)

Actual Total Syst Kwh @ Input =	215,211,299	
Estimated Co.Use Kwh @ Input =	982,395	
Estimated UT Kwh @ Input =	195,430,545	
Estimated AZ Kwh @ Input =	18,798,421	
Est Total System Kwh @ Input =	215,211,360	
Total Estimated - Actual (Kwh) =	61	(should = 0)

Actual Tot Syst 12CP Kw @ Input =	414,958	
Est Co. Use 12CP Kw @ Input =	2,520	
Estimated UT 12CP Kw @ Input =	382,027	
Estimated AZ 12CP Kw @ Input =	30,203	
Est System 12CP Kw @ Input =	414,750	
Total Estimated - Actual (Kw) =	-208	(should = 0)

GARKANE ENERGY--Utah
COST-OF-SERVICE STUDY
Year End 12-31-08

CLASSIFICATION FACTORS	CH	TOTALS	DEM-CP	DEM-PRI	DEM-SEC	ENERGY	CUST-PLT-M	CUST-SER	CUST-PLT-S	DIR-Deposit	DIR-Lighting	DIR-Impact	Dir-Fed Gov
Demand-CP	1	1.0000	1										
Demand-Primary	2	1.0000		1									
Demand-Secondary	3	1.0000			1								
Energy	4	1.0000				1							
Customer-Plant-Meters	5	1.0000					1						
Customer-Services	6	1.0000						1					
Customer-Plant-Services	7	1.0000							1				
Direct-Customer Deposits	8	1.0000								1			
Direct-Lighting	9	1.0000									1		
Direct-Impact Fees	10	1.0000										1	
Production Plant (calc)	11	1.0000	0.00000	0.00000	0.00000	1.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000
Distribution Plant (calc)	12	1.0000	0.00000	0.63177	0.24590	0.00000	0.05821	0.00000	0.05852	0.00000	0.00559	0.00000	0.00000
Prod+Transm+Distr Plant (calc)	13	1.0000	0.20313	0.43218	0.16822	0.11279	0.03982	0.00000	0.04004	0.00000	0.00382	0.00000	0.00000
Purch Pwr-Kw & Kwh(calc)	14	1.0000	0.56277	0.00000	0.00000	0.43723	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000
O&M-Power Prod Exp (calc)	15	1.0000	0.20299	0.43562	0.03788	0.00000	0.09945	0.21298	0.00500	0.00000	0.00608	0.00000	0.00000
Transmission Plant (calc)	16	1.0000	1.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000
General Plant (calc)	17	1.0000	0.20313	0.43218	0.16822	0.11279	0.03982	0.00000	0.04004	0.00000	0.00382	0.00000	0.00000
Direct-Fed Gov rates	18	1.0000											1

CLASSIFY RATE BASE	CH	TOTAL **	DEM-CP	DEM-PRI	DEM-SEC	ENERGY	CUST-PLT-M	CUST-SER	CUST-PLT-S	DIR-Deposit	DIR-Lighting	DIR-Impact	Dir-Fed Gov	checksum
PRODUCTION PLANT	4	5,961,584	0	0	0	5,961,584	0	0	0	0	0	0	0	0
														0
TRANSMISSION PLANT	1	10,737,081	10,737,081	0	0	0	0	0	0	0	0	0	0	0
														0
DISTRIBUTION PLANT														0
360-Land	2	302,446	0	302,446	0	0	0	0	0	0	0	0	0	0
361-Structures	2	0	0	0	0	0	0	0	0	0	0	0	0	0
362-Station equipment Alloc	2	5,934,708	0	5,934,708	0	0	0	0	0	0	0	0	0	0
363-Storage batteries	2	0	0	0	0	0	0	0	0	0	0	0	0	0
364-Poles,towers & fixtures	2	6,624,118	0	6,624,118	0	0	0	0	0	0	0	0	0	0
365-Overhead conductors	2	7,840,032	0	7,840,032	0	0	0	0	0	0	0	0	0	0
366-Undergrd conduit	2	124,501	0	124,501	0	0	0	0	0	0	0	0	0	0
367-Undergrd conductors	2	2,018,132	0	2,018,132	0	0	0	0	0	0	0	0	0	0
368-Line transformers	3	8,891,429	0	0	8,891,429	0	0	0	0	0	0	0	0	0
369-Services	7	2,116,166	0	0	0	0	0	0	2,116,166	0	0	0	0	0
370-Meters	5	2,104,881	0	0	0	0	2,104,881	0	0	0	0	0	0	0
371-Install on cust premises	9	106,384	0	0	0	0	0	0	0	0	106,384	0	0	0
373-St Lighting	9	95,790	0	0	0	0	0	0	0	0	95,790	0	0	0
Total Distribution Plant		36,158,585	0	22,843,936	8,891,429	0	2,104,881	0	2,116,166	0	202,174	0	0	0
														0
GENERAL PLANT	13	9,582,416	1,946,510	4,141,345	1,611,914	1,080,767	381,591	0	383,637	0	36,652	0	0	0
TOTAL PLANT IN SERVICE		62,439,666	12,683,591	26,985,281	10,503,343	7,042,352	2,486,472	0	2,499,802	0	238,826	0	0	0
														0
CWIP	13	4,156,893	844,404	1,796,533	699,255	468,841	165,536	0	166,423	0	15,900	0	0	0
Materials & Supplies	13	2,987,773	606,917	1,291,261	502,591	336,980	118,979	0	119,617	0	11,428	0	0	0
Prepayments	13	57,785	11,738	24,974	9,720	6,517	2,301	0	2,313	0	221	0	0	0
Cash Working Capital		1,040,231	278,401	354,553	53,186	119,250	70,872	137,189	10,075	2,270	4,573	0	9,863	0
Subtotal		8,242,683	1,741,461	3,467,321	1,264,752	931,589	357,688	137,189	298,428	2,270	32,122	0	9,863	0
LESS Accumulated depreciation														0
Production	11	2,870,856	0	0	0	2,870,856	0	0	0	0	0	0	0	0
Transmission	16	5,634,394	5,634,394	0	0	0	0	0	0	0	0	0	0	0
Distribution	12	10,512,992	0	6,641,800	2,585,154	0	611,987	0	615,268	0	58,781	0	0	0
General	17	4,647,906	944,146	2,008,740	781,852	524,221	185,089	0	186,081	0	17,778	0	0	0
Subtotal		23,666,147	6,578,539	8,650,540	3,367,006	3,395,077	797,076	0	801,349	0	76,559	0	0	0
														0
LESS Cust impact fees	10	530,636	0	0	0	0	0	0	0	0	0	530,636	0	0
														0
LESS Cust deposits	8	314,418	0	0	0	0	0	0	0	314,418	0	0	0	0
														0
TOTAL RATE BASE		46,171,148	7,846,512	21,802,061	8,401,090	4,578,864	2,047,083	137,189	1,996,881	-312,148	194,389	-530,636	9,863	0

CLASSIFY EXPENSES	CF	TOTAL **	DEM-CP	DEM-PRI	DEM-SEC	ENERGY	CUST-PLT-M	CUST-SER	CUST-PLT-S	DIR-Deposit	DIR-Lighting	DIR-Impact	Dir-Fed Gov	
POWER PRODUCTION														
Hydro O&M	11	261,151	0	0	0	261,151	0	0	0	0	0	0	0	0
Other O&M	11	32,677	0	0	0	32,677	0	0	0	0	0	0	0	0
Subtotal		293,827	0	0	0	293,827	0	0	0	0	0	0	0	0
Purchased Power-KW	1	2,446,226	2,446,226	0	0	0	0	0	0	0	0	0	0	0
Purchased Power-KWH	4	1,900,556	0	0	0	1,900,556	0	0	0	0	0	0	0	0
Purchased Power-Other	14	446,653	251,362	0	0	195,291	0	0	0	0	0	0	0	0
556-Syst contrl & ld dispatch	14	20,832	11,723	0	0	9,108	0	0	0	0	0	0	0	0
Subtotal		4,814,267	2,709,311	0	0	2,104,956	0	0	0	0	0	0	0	0
														0
TRANSMISSION O&M	16	680,907	680,907	0	0	0	0	0	0	0	0	0	0	0
														0
DISTRIBUTION OPER														0
580-Supervision	12	23,078	0	14,580	5,675	0	1,343	0	1,351	0	129	0	0	0
581-Load dispatching	12	25,048	0	15,825	6,159	0	1,458	0	1,466	0	140	0	0	0
582-Station	2	20,077	0	20,077	0	0	0	0	0	0	0	0	0	0
583-Overhead lines	2	78,636	0	78,636	0	0	0	0	0	0	0	0	0	0
584-Undergrd lines	2	6,121	0	6,121	0	0	0	0	0	0	0	0	0	0
585-Street Lights	9	3,792	0	0	0	0	0	0	0	0	3,792	0	0	0
586-Meters	5	180,285	0	0	0	0	180,285	0	0	0	0	0	0	0
587-Cust installations	6	5,551	0	0	0	0	0	5,551	0	0	0	0	0	0
588-Misc	12	202,304	0	127,810	49,747	0	11,777	0	11,840	0	1,131	0	0	0
589-Rents	12	192	0	121	47	0	11	0	11	0	1	0	0	0
Subtotal		545,083	0	263,169	61,628	0	194,874	5,551	14,668	0	5,193	0	0	0
DISTRIBUTION MAINT														0
590-Maint suprv & engr	12	23,343	0	14,747	5,740	0	1,359	0	1,366	0	131	0	0	0
592-Station equipment	2	136,289	0	136,289	0	0	0	0	0	0	0	0	0	0
593-Overhead lines	2	880,680	0	880,680	0	0	0	0	0	0	0	0	0	0
594-Undergrd lines	2	158,210	0	158,210	0	0	0	0	0	0	0	0	0	0
595-Line transformers	3	56,529	0	0	56,529	0	0	0	0	0	0	0	0	0
596-Maint of St Lights	9	15,012	0	0	0	0	0	0	0	0	15,012	0	0	0
597-Meters	5	136,602	0	0	0	0	136,602	0	0	0	0	0	0	0
598-Misc	12	12,881	0	8,138	3,167	0	750	0	754	0	72	0	0	0
Subtotal		1,419,547	0	1,198,065	65,437	0	138,711	0	2,120	0	15,214	0	0	0
CUSTOMER EXPENSES														0
901-Supervision-accts	6	28,109	0	0	0	0	0	28,109	0	0	0	0	0	0
902-Meter reading	6	193,687	0	0	0	0	0	193,687	0	0	0	0	0	0
903-Records & collection	6	373,249	0	0	0	0	0	373,249	0	0	0	0	0	0
904-Uncollectibles	8	0	0	0	0	0	0	0	0	0	0	0	0	0
908-Cust assistance	6	74,729	0	0	0	0	0	74,729	0	0	0	0	0	0
909-Info & instruc adv	6	21,591	0	0	0	0	0	21,591	0	0	0	0	0	0
910-Misc cust svc & info	6	2,015	0	0	0	0	0	2,015	0	0	0	0	0	0
912-Demonstrating & selling	6	15,495	0	0	0	0	0	15,495	0	0	0	0	0	0
913-Advertising ADM	6	0	0	0	0	0	0	0	0	0	0	0	0	0
Subtotal		708,875	0	0	0	0	0	708,875	0	0	0	0	0	0
														0
ADMINISTRATIVE & GEN														0
920-A&G salaries-alloc	13	370,743	75,310	160,228	62,365	41,815	14,764	0	14,843	0	1,418	0	0	0
920-A&G salaries-Dir	18	80,000	0	0	0	0	0	0	0	0	0	0	80,000	0
921-Office supplies & exp	13	215,109	43,696	92,966	36,185	24,261	8,566	0	8,612	0	823	0	0	0
923-Outside services	13	96,343	19,571	41,638	16,206	10,866	3,837	0	3,857	0	369	0	0	0
924-Property insurance	13	139,392	28,315	60,243	23,448	15,722	5,551	0	5,581	0	533	0	0	0
925-Injuries & damages	13	125,883	25,571	54,404	21,176	14,198	5,013	0	5,040	0	481	0	0	0
926-Employee pension/benefits	15	1,099,328	223,151	478,884	41,642	0	109,324	234,136	5,502	0	6,688	0	0	0
928-Regulatory expenses	15	18,461	3,747	8,042	699	0	1,836	3,932	92	0	112	0	0	0
930-Misc general expenses	15	752,464	152,741	327,785	28,503	0	74,830	160,260	3,766	0	4,578	0	0	0
931-Rents	13	0	0	0	0	0	0	0	0	0	0	0	0	0
932-Maint of general plant	17	125,522	25,498	54,248	21,115	14,157	4,999	0	5,025	0	480	0	0	0
Subtotal		3,023,245	597,600	1,278,439	251,339	121,019	228,719	398,328	52,318	0	15,482	0	80,000	0
														0
DEPRECIATION EXPENSE														0
Production	11	135,168	0	0	0	135,168	0	0	0	0	0	0	0	0
Transmission	16	274,038	274,038	0	0	0	0	0	0	0	0	0	0	0
Distribution	12	1,067,710	0	674,548	262,551	0	62,154	0	62,487	0	5,970	0	0	0
General	17	455,261	92,479	196,755	76,582	51,347	18,129	0	18,227	0	1,741	0	0	0
Subtotal		1,932,176	366,516	871,303	339,133	186,516	80,283	0	80,714	0	7,711	0	0	0
														0
Taxes-Property-Electric Utility	13	251,402	51,068	108,651	42,290	28,355	10,011	0	10,065	0	962	0	0	0
Taxes-other	13	63,615	12,922	27,493	10,701	7,175	2,533	0	2,547	0	243	0	0	0
Interest on cust deposits	8	18,409	0	0	0	0	0	0	0	18,409	0	0	0	0
														0
TOTAL EXPENSES		13,751,353	4,418,326	3,747,120	770,528	2,741,848	655,132	1,112,754	162,431	18,409	44,806	0	80,000	0

CUSTOMER FACTORS		TOTAL	Residential21	Irrigation 24	Sm Comm 25	St/Sec Lts27	Comm 28	Municipal 29	Fed Gov 32	ExLgPwr15	K-Res 21	K-GS1 25	K-St Lts 21	K-GS2 28	K-Fed G 32	cksum
Average No. Customers **		10,818	7,835	105	1,058	26	123	11	91	1	1,185	361	2	15	5	0
Weighting Factors-Plant-meters			1.00	3.50	2.00	0.00	6.00	6.00	2.00	40.00	1.00	2.00	0.00	6.00	2.00	
Weighting Factors-Plant-svc drp			1.00	1.00	1.00	0.00	4.00	4.00	1.00	0.00	1.00	1.00	0.00	4.00	1.00	
Weighting Factors-Services			6.00	15.00	8.00	1.00	8.00	8.00	15.00	60.00	6.00	8.00	1.00	8.00	15.00	
Wgt'd Cust-Plant-Meters		13,349	7,835	367	2,117	0	735	66	182	40	1,185	722	0	91	10	0
Wgt'd Cust-Services		69,765	47,009	1,571	8,466	26	980	88	1,366	60	7,113	2,889	2	121	75	0
Wgt'd Cust-Plant-Services		11,235	7,835	105	1,058	0	490	44	91	0	1,185	361	0	60	5	0

ALLOCATION FACTORS	AF	TOTAL	Residential21	Irrigation 24	Sm Comm 25	St/Sec Lts27	Comm 28	Municipal 29	Fed Gov 32	ExLgPwr15	K-Res 21	K-GS1 25	K-St Lts 21	K-GS2 28	K-Fed G 32	
Demand-CP (Sys 12 CP)	1	1.0000	0.3943	0.0133	0.1317	0.0007	0.1869	0.0033	0.0098	0.0989	0.0642	0.0594	0.0003	0.0357	0.0016	0
Demand-Primary (sch peak)	2	1.0000	0.4894	0.0380	0.1134	0.0023	0.1304	0.0045	0.0081	0.0539	0.0820	0.0521	0.0010	0.0234	0.0015	0
Demand-Secondary (MCDxDcf)	3	1.0000	0.6972	0.0169	0.0729	0.0010	0.0651	0.0025	0.0054	0.0000	0.0901	0.0343	0.0004	0.0135	0.0009	0
Energy (MWH)	4	1.0000	0.4021	0.0218	0.1267	0.0027	0.1328	0.0028	0.0100	0.1304	0.0720	0.0619	0.0012	0.0343	0.0013	0
Customer-Plant-Meters (calc)	5	1.0000	0.5869	0.0275	0.1585	0.0000	0.0551	0.0049	0.0136	0.0030	0.0888	0.0541	0.0000	0.0068	0.0007	0
Customer-Services (calc)	6	1.0000	0.6738	0.0225	0.1214	0.0004	0.0140	0.0013	0.0196	0.0009	0.1019	0.0414	0.0000	0.0017	0.0011	0
Cust-Plant-Services (Calc)	7	1.0000	0.6974	0.0093	0.0942	0.0000	0.0436	0.0039	0.0081	0.0000	0.1055	0.0321	0.0000	0.0054	0.0004	0
Lighting expense (# lamps)	9	1.0000	0.0000	0.0000	0.0000	0.8248	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.1752	0.0000	0.0000	0
Lighting plant (rel fixture cost)	10	1.0000	0.0000	0.0000	0.0000	0.6927	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.3073	0.0000	0.0000	0
Average customers	11	1.0000	0.7243	0.0097	0.0978	0.0024	0.0113	0.0010	0.0084	0.0001	0.1096	0.0334	0.0002	0.0014	0.0005	0
Deposits	12	1.0000	0.5660	0.0052	0.0926	0.0000	0.0813	0.0000	0.0000	0.0000	0.2055	0.0495	0.0000	0.0000	0.0000	0
Direct-Fed Gov (per M.A.)	13	1.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.5000	0.0000	0.0000	0.0000	0.0000	0.0000	0.5000	0
																0

REVENUES	AF	TOTAL	Residential21	Irrigation 24	Sm Comm 25	St/Sec Lts27	Comm 28	Municipal 29	Fed Gov 32	ExLgPwr15	K-Res 21	K-GS1 25	K-St Lts 21	K-GS2 28	K-Fed G 32	
REVENUES-Rate **	DIF	14,220,578	5,818,283	285,076	1,908,127	90,668	1,838,355	50,630	217,492	1,519,776	1,046,736	906,875	30,172	477,849	30,539	0
REVENUE CREDITS																0
450-Penalties	11	18,706	13,548	181	1,830	44	212	19	158	2	2,050	624	3	26	9	0
451-Conn,Disc & ret ck fees	11	36,104	26,149	350	3,532	86	409	37	304	3	3,956	1,205	6	50	17	0
454-Rents fr elec property	2	25,702	12,579	977	2,915	59	3,351	116	208	1,385	2,107	1,339	25	602	38	0
456-other electric revenue	2	69,737	34,130	2,651	7,908	161	9,092	316	563	3,758	5,717	3,634	68	1,634	103	0
456.01-wheeling revenue	1	571,009	225,150	7,584	75,211	407	106,726	1,873	5,588	56,471	36,656	33,908	172	20,359	905	0
Subtotal		721,258	311,556	11,743	91,396	758	119,790	2,361	6,820	61,619	50,486	40,710	275	22,671	1,071	0
TOTAL REVENUES		14,941,836	6,129,839	296,819	1,999,523	91,426	1,958,145	52,991	224,312	1,581,395	1,097,222	947,585	30,447	500,520	31,610	0
																0

ALLOCATE EXPENSES	AF	TOTAL	Residential21	Irrigation 24	Sm Comm 25	St/Sec Lts27	Comm 28	Municipal 29	Fed Gov 32	ExLgPwr15	K-Res 21	K-GS1 25	K-St Lts 21	K-GS2 28	K-Fed G 32	
Demand-CP	1	4,418,326	1,742,149	58,683	581,964	3,153	825,820	14,490	43,236	436,958	283,632	262,368	1,334	157,536	7,003	0
-Primary	2	3,747,120	1,833,894	142,460	424,936	8,663	488,547	16,969	30,265	201,931	307,208	195,265	3,664	87,776	5,540	0
-Secondary	3	770,528	537,221	13,031	56,150	763	50,131	1,893	4,130	0	69,394	26,393	333	10,370	719	0
Total Demand		8,935,973	4,113,265	214,174	1,063,051	12,580	1,364,498	33,351	77,631	638,889	660,235	484,026	5,330	255,682	13,262	0
Energy	4	2,741,848	1,102,626	59,690	347,474	7,527	364,231	7,542	27,399	357,446	197,282	169,687	3,281	93,990	3,672	0
Customer-Plant-Meters	5	655,132	384,506	17,993	103,870	0	36,071	3,239	8,940	1,963	58,176	35,441	0	4,441	491	0
-Services	6	1,112,754	749,796	25,062	135,033	409	15,631	1,404	21,792	957	113,445	46,074	31	1,925	1,196	0
-Plant-Services	7	162,431	113,275	1,514	15,300	0	7,084	636	1,317	0	17,139	5,221	0	872	72	0
Total Customer		1,930,317	1,247,577	44,569	254,204	409	58,787	5,279	32,049	2,920	188,759	86,736	31	7,238	1,759	0
Direct-Cust Deposits	12	18,409	10,419	96	1,705	0	1,496	0	0	0	3,783	910	0	0	0	0
Direct-Lighting	9	44,806	0	0	0	36,956	0	0	0	0	0	0	7,851	0	0	0
Direct-Impact Fees	3	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Direct-Fed Gov	13	80,000	0	0	0	0	0	0	40,000	0	0	0	0	0	40,000	0
																0
TOTAL EXPENSES		13,751,353	6,473,887	318,530	1,666,432	57,471	1,789,011	46,172	177,080	999,255	1,050,059	741,360	16,493	356,910	58,693	0
																0
NET OPER INCOME		1,190,483	-344,049	-21,710	333,091	33,955	169,134	6,819	47,233	582,140	47,163	206,226	13,955	143,610	-27,083	0
																0
																0

ALLOCATE RATE BASE	AF	TOTAL	Residential21	Irrigation 24	Sm Comm 25	St/Sec Lts27	Comm 28	Municipal 29	Fed Gov 32	ExLgPwr15	K-Res 21	K-GS1 25	K-St Lts 21	K-GS2 28	K-Fed G 32	0
Demand-CP	1	7,846,512	3,093,886	104,216	1,033,511	5,600	1,466,575	25,732	76,784	775,994	503,703	465,939	2,368	279,768	12,436	0
-Primary	2	21,802,061	10,670,243	828,883	2,472,428	50,405	2,842,539	98,729	176,094	1,174,905	1,787,444	1,136,122	21,318	510,714	32,236	0
-Secondary	3	8,401,090	5,857,340	142,077	612,211	8,323	546,578	20,636	45,027	0	756,609	287,760	3,628	113,062	7,838	0
Total Demand		38,049,663	19,621,469	1,075,175	4,118,150	64,328	4,855,692	145,098	297,905	1,950,899	3,047,756	1,889,822	27,315	903,544	52,511	0
Energy	4	4,578,864	1,841,377	99,682	580,278	12,569	608,263	12,595	45,757	596,932	329,460	283,376	5,480	156,963	6,132	0
Customer-Plant-Meters	5	2,047,083	1,201,461	56,221	324,562	0	112,711	10,121	27,935	6,134	181,782	110,743	0	13,878	1,533	0
-Services	6	137,189	92,441	3,090	16,648	50	1,927	173	2,687	118	13,986	5,680	4	237	147	0
-Plant-Services	7	1,996,881	1,392,575	18,618	188,095	0	87,093	7,821	16,189	0	210,698	64,179	0	10,724	889	0
Total Customer		4,181,153	2,686,477	77,930	529,305	50	201,732	18,115	46,811	6,252	406,466	180,603	4	24,839	2,570	0
Direct-Cust Deposits	12	-312,148	-176,666	-1,634	-28,902	0	-25,367	0	0	0	-64,142	-15,437	0	0	0	0
Direct-Lighting	10	194,389	0	0	0	134,648	0	0	0	0	0	0	59,741	0	0	0
Direct-Impact Fees	3	-530,636	-369,966	-8,974	-38,669	-526	-34,523	-1,303	-2,844	0	-47,790	-18,176	-229	-7,141	-495	0
Direct-Fed Gov	13	9,863	0	0	0	0	0	0	4,932	0	0	0	0	0	4,932	0
																0
TOTAL RATE BASE		46,171,148	23,602,692	1,242,179	5,160,162	211,070	5,605,796	174,504	392,560	2,554,083	3,671,751	2,320,189	92,310	1,078,204	65,649	0
																0
% Return on Rate Base		2.578%	-1.46%	-1.75%	6.46%	16.09%	3.02%	3.91%	12.03%	22.79%	1.28%	8.89%	15.12%	13.32%	-41.25%	
		TOTAL	Residential21	Irrigation 24	Sm Comm 25	St/Sec Lts27	Comm 28	Municipal 29	Fed Gov 32	ExLgPwr15	K-Res 21	K-GS1 25	K-StLts27	K-GS2 28	K-Fed G 32	0
($) Return with Target ROR =		5.28%														0
Demand Total		2,010,332	1,036,689	56,806	217,580	3,399	256,548	7,666	15,740	103,075	161,026	99,848	1,443	47,738	2,774	0
Energy Total		241,922	97,288	5,267	30,659	664	32,137	665	2,418	31,539	17,407	14,972	290	8,293	324	0
Customer Total		220,909	141,938	4,117	27,966	3	10,658	957	2,473	330	21,475	9,542	0	1,312	136	0
Direct-Cust Deposits		-16,492	-9,334	-86	-1,527	0	-1,340	0	0	0	-3,389	-816	0	0	0	0
Direct-Lighting		10,270	0	0	0	7,114	0	0	0	0	0	0	3,156	0	0	0
Direct-Impact Fees		-28,036	-19,547	-474	-2,043	-28	-1,824	-69	-150	0	-2,525	-960	-12	-377	-26	0
Direct-Fed Gov		521	0	0	0	0	0	0	261	0	0	0	0	0	261	0
SUBTOTAL =		2,439,426	1,247,035	65,630	272,634	11,152	296,179	9,220	20,741	134,944	193,995	122,586	4,877	56,966	3,469	0
Total COS (Return+Exp-Rev Credits)																0
Demand Total		10,332,342	4,858,548	259,294	1,192,554	15,322	1,500,052	38,643	127,123	680,349	774,256	544,032	6,496	280,448	55,225	0
Energy Total		2,983,769	1,199,914	64,957	378,132	8,191	396,368	8,207	29,817	388,985	214,689	184,659	3,571	102,283	3,996	0
Customer Total		2,153,409	1,350,903	48,165	276,985	44,352	68,980	6,180	34,060	3,245	204,623	94,544	11,028	8,474	1,870	0
																0
Total Cost-of-Service		15,469,520	7,409,366	372,416	1,847,671	67,865	1,965,400	53,031	191,000	1,072,579	1,193,568	823,235	21,095	391,205	61,090	0
Total Sales Revenues		14,220,578	5,818,283	285,076	1,908,127	90,668	1,838,355	50,630	217,492	1,519,776	1,046,736	906,875	30,172	477,849	30,539	0
Deficit		1,248,942	1,591,083	87,340	-60,456	-22,803	127,045	2,401	-26,492	-447,197	146,832	-83,640	-9,077	-86,644	30,551	0
% Rate Increase Required		8.78%	27.35%	30.64%	-3.17%	-25.15%	6.91%	4.74%	-12.18%	-29.43%	14.03%	-9.22%	-30.09%	-18.13%	100.04%	
ANNUAL BILLING UNITS																
Cust-months or lamp-months		143,520	94,018	1,257	12,699	11,580	1,470	132	1,093	12	14,225	4,333	2,460	181	60	0
KWH (@ meter)		176,953,880	70,811,158	3,833,344	22,314,915	483,360	23,391,066	484,345	1,759,601	23,658,000	12,669,563	10,897,387	210,720	6,204,620	235,801	0
KW (MCD @ meter)		1,112,847	694,964	11,233	95,808	1,414	86,333	2,483	6,499	33,660	117,073	44,590	616	17,077	1,097	0
																0
AVERAGE UNIT COST OF SERVICE																
Cust--$/Cust/month		15.00	14.37	38.32	21.81	3.83	46.93	46.82	31.16	270.44	14.38	21.82	4.48	46.82	31.16	
Energy--Cents/kwh		1.69	1.69	1.69	1.69	1.69	1.69	1.69	1.69	1.64	1.69	1.69	1.69	1.65	1.69	
Demand--$/Kw		9.28	6.99	23.08	12.45	10.84	17.38	15.56	19.56	20.21	6.61	12.20	10.54	16.42	50.34	
Demand+Energy--Cents/kwh			8.56								7.81					
Unit COS with flat cents/Kwh		8.74	10.46	9.72	8.28	14.04	8.40	10.95	10.85	4.53	9.42	7.55	10.01	6.31	25.91	

STREET & SECURITY LIGHTS

UTAH (w/o Kanab)	UT 100 watt		UT 400 watt
Avg. No. lamps/month	951.0		14.0
Kwh/lamp/month	40		160
Kw demand/lamp	0.117		0.468
Customer Cost/lamp/month	3.83		3.83
Energy Cost/lamp/month	0.68		2.71
Demand Cost/lamp/month	1.27		5.07
Total Cost $/lamp/month	5.78		11.61

Kanab	K 100 watt	K 250 watt	K 400 watt
Avg. No. lamps/month	111.0	32.0	62
Kwh/lamp/month	40	100	160
Kw demand/lamp	0.117	0.293	0.468
Customer Cost/lamp/month	4.48	4.48	4.48
Energy Cost/lamp/month	0.68	1.69	2.71
Demand Cost/lamp/month	1.23	3.08	4.93
Total Cost $/lamp/month	6.39	9.26	12.13

Cost-of-Service Summary

With existing debt
Year End 12-31-08

Rate Schedule	Earned % Return on Rate Base	ROR Index No.	% Rate Incr Required for ROR of 5.28%
Residential 21	-1.46%	-0.57	27.35%
Irrigation 24	-1.75%	-0.68	30.64%
Small Commercial 25	6.46%	2.50	-3.17%
Lighting 27	16.09%	6.24	-25.15%
Commercial 28	3.02%	1.17	6.91%
Municipal 29	3.91%	1.52	4.74%
Federal Gov 32	12.03%	4.67	-12.18%
Ex Lg Power 15	22.79%	8.84	-29.43%
Kanab-Res 21	1.28%	0.50	14.03%
Kanab-GS1 25	8.89%	3.45	-9.22%
Kanab-St Lights 27	15.12%	5.86	-30.09%
Kanab-GS2 28	13.32%	5.17	-18.13%
Kanab-Fed Gov 32	-41.25%	-16.00	100.04%
TOTAL UTAH	2.58%	1.00	8.78%

Utah Cost of Service
With Utah/Kanab Rates Consolidated

Garkane Energy
Year End 12-31-08

12-20-08

	TOTAL	Residential21	Irrigation 24	Sm Comm 25	St/Sec Lts27
Total COS (Return+Exp-Rev Credits)					
Demand Total	10,332,342	5,632,804	259,294	1,736,586	21,818
Energy Total	2,983,769	1,414,604	64,957	562,792	11,761
Customer Total	2,153,409	1,555,526	48,165	371,528	55,380
Total Cost-of-Service	15,469,520	8,602,934	372,416	2,670,906	88,959
Total Sales Revenues	14,220,578	6,865,019	285,076	2,815,002	120,840
Deficit	1,248,942	1,737,915	87,340	-144,096	-31,881
% Rate Increase Required	**8.78%**	**25.32%**	**30.64%**	**-5.12%**	**-26.38%**
ANNUAL BILLING UNITS					
Cust-months or lamp-months	143,520	108,243	1,257	17,032	14,040
KWH (@ meter)	176,953,880	83,480,721	3,833,344	33,212,302	694,080
KW (MCD @ meter)	1,112,847	812,037	11,233	140,398	2,030
AVERAGE UNIT COST OF SERVICE					
Cust--$/Cust/month	15.00	14.37	38.32	21.81	3.94
Energy--Cents/kwh	1.69	1.69	1.69	1.69	1.69
Demand--$/Kw	9.28	6.94	23.08	12.37	10.75
Demand+Energy--Cents/kwh		8.44			
Unit COS with flat cents/Kwh	8.74	10.31	9.72	8.04	12.82

STREET & SECURITY LIGHTS	100 watt	250 watt	400 watt
Avg. No. lamps/month	1,062.0	32.0	76.0
Kwh/lamp/month	40.0	100.0	160.0
Kw demand/lamp	0.117	0.293	0.468
Customer Cost/lamp/month	3.94	3.94	3.94
Energy Cost/lamp/month	0.68	1.69	2.71
Demand Cost/lamp/month	1.26	3.14	5.03
Total Cost $/lamp/month	5.88	8.78	11.69

Cost-of-Service Summary **With existing debt With Utah/Kanab Consolidated**

Rate Schedule	**% Rate Incr Required for ROR of 5.28%**
Residential 21	25.32%
Irrigation 24	30.64%
Small Commercial 25	-5.12%
Lighting 27	-26.38%
Commercial 28	1.74%
Municipal 29	4.74%

Federal Gov 32	1.64%
Ex Lg Power 15	-29.43%
TOTAL UTAH	8.78%

Comm 28	Municipal 29	Fed Gov 32	ExLgPwr15
1,780,500	38,643	182,347	680,349
498,651	8,207	33,813	388,985
77,454	6,180	35,930	3,245
2,356,605	53,031	252,090	1,072,579
2,316,204	50,630	248,031	1,519,776
40,401	2,401	4,059	-447,197
1.74%	4.74%	1.64%	-29.43%
1,651	132	1,153	12
29,595,686	484,345	1,995,402	23,658,000
103,410	2,483	7,596	33,660
46.91	46.82	31.16	270.44
1.68	1.69	1.69	1.64
17.22	15.56	24.01	20.21
7.96	10.95	12.63	4.53

GECOS09 AZ
TOTAL ARIZONA
4-6-09

With existing debt

CHECKSUM
OK

COST-OF-SERVICE STUDY
GARKANE ENERGY- Arizona
Year End 12-31-08

1.156971 = Demand Loss Factor (sec) **
1.1099 = Energy Loss Factor (sec)

1. Residential 01	L#	JAN	FEB	MAR	APR	MAY	JUN	JUL
KWH @ Meter **	1	945,771	902,532	684,535	618,422	492,834	489,337	664,855
KWH @ Input	2	1,049,692	1,001,702	759,751	686,374	546,986	543,105	737,909
Load Factor (PU) **	3	0.2150	0.2050	0.1790	0.1510	0.1330	0.1410	0.1230
Max Cust Demand (KW) calc	4	5,913	6,551	5,140	5,688	4,981	4,820	7,265
Schedule Coincidence Factor	5	0.358	0.364	0.314	0.261	0.255	0.263	0.298
Sched PK @ Meter (KW)	6	2,117	2,385	1,614	1,485	1,270	1,268	2,165
Sched PK @ Input (KW)	7	2,449	2,759	1,867	1,718	1,469	1,467	2,505
System Coincidence Factor	8	0.747	0.804	0.559	0.559	0.541	0.534	0.556
Coincident PK @ Input (KW)	9	1,829	2,218	1,044	960	795	783	1,393

1.1570 = Demand Loss Factor (sec)
1.1099 = Energy Loss Factor (sec)

2. Small Commercial GS1 05	L#	JAN	FEB	MAR	APR	MAY	JUN	JUL
KWH @ Meter **	1	229,765	223,539	187,271	205,771	199,093	244,239	290,028
KWH @ Input	2	255,011	248,101	207,848	228,381	220,969	271,076	321,896
Load Factor (PU)calc'd	3	0.4140	0.4576	0.3439	0.3390	0.2908	0.3312	0.3802
Max Cust Demand (KW)**	4	746	727	732	843	920	1,024	1,025
Schedule Coincidence Factor	5	0.506	0.528	0.583	0.571	0.510	0.527	0.672
Sched PK @ Meter (KW)	6	377	384	427	481	469	540	689
Sched PK @ Input (KW)	7	437	444	494	557	543	625	797
System Coincidence Factor	8	0.700	0.771	0.900	0.820	1.000	0.890	0.865
Coincident PK @ Input (KW)	9	306	342	444	457	543	556	690

1.1570 = Demand Loss Factor (sec)
1.1099 = Energy Loss Factor (sec)

3. Public Authorities GS1 06	L#	JAN	FEB	MAR	APR	MAY	JUN	JUL
KWH @ Meter **	1	62,635	63,378	38,432	28,838	19,507	11,287	18,666
KWH @ Input	2	69,517	70,342	42,655	32,007	21,650	12,527	20,717
Load Factor (PU)calc'd	3	0.5609	0.5810	0.3808	0.2669	0.1949	0.1102	0.2090
Max Cust Demand (KW)**	4	150	162	136	150	135	142	120
Schedule Coincidence Factor	5	0.506	0.528	0.583	0.571	0.510	0.527	0.672
Sched PK @ Meter (KW)	6	76	86	79	86	69	75	81
Sched PK @ Input (KW)	7	88	99	91	99	79	87	93
System Coincidence Factor	8	0.700	0.771	0.900	0.820	1.000	0.890	0.865
Coincident PK @ Input (KW)	9	62	76	82	81	79	77	81

1.1224 = Demand Loss Factor (pri/sec comb)
1.0769 = Energy Loss Factor (pri/sec comb)

4. Large Power GS2 08	L#	JAN	FEB	MAR	APR	MAY	JUN	JUL
KWH @ Meter **	1	300,150	341,950	277,555	411,830	565,960	402,815	462,215
KWH @ Input	2	323,236	368,251	298,903	443,506	609,491	433,798	497,767
Load Factor (PU)calc'd	3	0.6993	1.2291	0.8537	0.8563	0.7891	0.6416	0.8629
Max Cust Demand (KW)**	4	577	414	437	668	964	872	720
Schedule Coincidence Factor	5	0.921	0.794	0.900	0.780	0.700	0.733	0.706
Sched PK @ Meter (KW)	6	531	329	393	521	675	639	508
Sched PK @ Input (KW)	7	596	369	441	585	757	717	571
System Coincidence Factor	8	0.963	0.862	0.957	0.902	0.780	0.976	0.910
Coincident PK @ Input (KW)	9	574	318	422	528	591	700	519

1.1570 = Demand Loss Factor (sec)
1.1099 = Energy Loss Factor (sec)

5. Irrigation 04	L#	JAN	FEB	MAR	APR	MAY	JUN	JUL
KWH @ Meter **	1	5,576	6,770	7,537	35,418	61,750	67,330	101,910
KWH @ Input	2	6,189	7,514	8,365	39,310	68,535	74,728	113,108
Load Factor (PU) calc	3	*0.1372*	*0.1493*	*0.1371*	*0.2116*	*0.3398*	*0.3638*	*0.5488*
Max Cust Demand (KW) **	4	55	67	74	232	244	257	250
Schedule Coincidence Factor	5	0.408	0.000	0.067	0.999	0.710	0.883	0.790
Sched PK @ Meter (KW)	6	22	0	5	232	173	227	197
Sched PK @ Input (KW)	7	26	0	6	269	201	263	228
System Coincidence Factor	8	0.242	0.000	0.833	0.041	0.780	0.796	0.763
Coincident PK @ Input (KW)	9	6	0	5	11	156	209	174

1.1570 = Demand Loss Factor (sec)
1.1099 = Energy Loss Factor (sec)

6. Street & Security Lights 07	L#	JAN	FEB	MAR	APR	MAY	JUN	JUL
KWH @ Meter **	1	1,920	1,920	1,920	1,920	1,920	1,920	1,920
KWH @ Input	2	2,131	2,131	2,131	2,131	2,131	2,131	2,131
Load Factor (PU)calc'd	3	0.4595	0.5088	0.4595	0.4748	0.4595	0.4748	0.4595
Max Cust Demand (KW) **	4	6	6	6	6	6	6	6
Schedule Coincidence Factor	5	1	1	1	1	1	1	1
Sched PK @ Meter (KW)	6	6	6	6	6	6	6	6
Sched PK @ Input (KW)	7	6	6	6	6	6	6	6
System Coincidence Factor	8	1	0	0	0	0	0	0
Coincident PK @ Input (KW)	9	6	0	0	0	0	0	0

Monthly Estimated CP

	JAN	FEB	MAR	APR	MAY	JUN	JUL
Tot Estimated AZ CP Kw @input =	2,784	2,955	1,998	2,037	2,165	2,326	2,856

SUMMARY Estimated Loads	TOTAL	Residential 01	Sm Comm 05	Pub Auth 06	Lg Power 08	Irrigation 04	St Lts 07
KWH @ Meter	17,102,033	7,889,400	2,768,124	373,265	5,544,645	503,559	23,040
KWH @ Input	18,798,421	8,756,282	3,072,284	414,279	5,971,114	558,890	25,572
Max Cust Dem-NCP mo (kw)	10,849	8,031	1,025	162	1,341	284	6
Distr ln transf design CF *		0.95	1.00	1.00	1.00	1.00	1.00
MCD (kw) X DCF	10,447	7,629	1,025	162	1,341	284	6
Sched Pk Month @ Input (kw)	5,169	2,759	798	115	1,162	328	6
Sys 12CP @ Input (KW)	30,203	15,581	5,624	892	7,261	832	13

* based on avg of 1.5 res custs per line transf, a summer design coincidence factor of 0.95 accounts for diversity in sizing transf

Estimated AZ KWH @ Input =	18,798,421
Est AZ Sys 12CP KW @ input=	30,203

GARKANE ENERGY--Arizona
COST-OF-SERVICE STUDY
Year End 12-31-08

CLASSIFICATION FACTORS	CF	TOTALS	DEM-CP	DEM-PRI	DEM-SEC	ENERGY	CUST-PLT-M	CUST-SER
Demand-CP	1	1.0000	1					
Demand-Primary	2	1.0000		1				
Demand-Secondary	3	1.0000			1			
Energy	4	1.0000				1		
Customer-Plant-Meters	5	1.0000					1	
Customer-Services	6	1.0000						1
Customer-Plant-Services	7	1.0000						
Direct-Cust Deposits	8	1.0000						
Direct-Lighting	9	1.0000						
Direct-Impact Fees	10	1.0000						
Production Plant (calc)	11	1.0000	0.00000	0.00000	0.00000	1.00000	0.00000	0.00000
Distribution Plant (calc)	12	1.0000	0.00000	0.83896	0.06110	0.00000	0.01607	0.00000
Prod+Transm+Distr Plant (calc)	13	1.0000	0.17454	0.59314	0.04320	0.11847	0.01136	0.00000
Purchased Pwr-Kw & Kwh(calc)	14	1.0000	0.51288	0.00000	0.00000	0.48712	0.00000	0.00000
O&M-Power Prod Exp (calc)	15	1.0000	0.18696	0.59979	0.01032	0.00000	0.03039	0.15920
Transmission Plant (calc)	16	1.0000	1	0	0	0	0	0
General Plant (calc)	17	1.0000	0.17454	0.59314	0.04320	0.11847	0.01136	0.00000
Direct Lg Power 08	18	1.0000						

CLASSIFY RATE BASE	CF	TOTAL **	DEM-CP	DEM-PRI	DEM-SEC	ENERGY	CUST-PLT-M	CUST-SER
PRODUCTION PLANT	4	576,169	0	0	0	576,169	0	0
TRANSMISSION PLANT	1	848,869	848,869	0	0	0	0	0
DISTRIBUTION PLANT								
360-Land	2	40,889	0	40,889	0	0	0	0
362-Station equipment	2	973,449	0	973,449	0	0	0	0
364-Poles,towers & fixtures	2	689,485	0	689,485	0	0	0	0
365-Overhead conductors	2	1,131,441	0	1,131,441	0	0	0	0
366-Undergrd conduit	2	7,227	0	7,227	0	0	0	0
367-Undergrd conductors	2	42,309	0	42,309	0	0	0	0
368-Line transformers	3	210,101	0	0	210,101	0	0	0
369-Services	*7*	*277,242*	*0*	*0*	*0*	*0*	*0*	*0*
370-Meters	5	55,265	0	0	0	0	55,265	0
371-Install on cust premises	9	3,038	0	0	0	0	0	0
373-St Lighting	9	8,105	0	0	0	0	0	0
Total Distribution Plant		3,438,549	0	2,884,798	210,101	0	55,265	0
GENERAL PLANT	13	881,713	153,890	522,981	38,089	104,453	10,019	0
TOTAL PLANT IN SERVICE		5,745,299	1,002,760	3,407,779	248,190	680,621	65,283	0
CWIP	13	0	0	0	0	0	0	0
Materials & Supplies	13	274,916	47,983	163,064	11,876	32,568	3,124	0
Prepayments	13	5,317	928	3,154	230	630	60	0
Cash Working Capital		90,987	21,749	41,613	1,186	11,345	1,843	8,806
Subtotal		371,219	70,660	207,831	13,291	44,543	5,027	8,806
LESS Accumulated depreciation								
Production	11	277,459	0	0	0	277,459	0	0
Transmission	16	445,453	445,453	0	0	0	0	0
Distribution	12	1,692,787	0	1,420,177	103,432	0	27,207	0
General	17	427,671	74,644	253,669	18,475	50,664	4,860	0
Subtotal		2,843,370	520,097	1,673,847	121,907	328,124	32,066	0
LESS Cust impact fees	10	0	0	0	0	0	0	0
LESS Cust deposits	8	55,268	0	0	0	0	0	0
TOTAL RATE BASE		3,217,881	553,323	1,941,763	139,574	397,041	38,244	8,806

CLASSIFY EXPENSES	CF	TOTAL **	DEM-CP	DEM-PRI	DEM-SEC	ENERGY	CUST-PLT-M	CUST-SER
POWER PRODUCTION								
Power Production Hydro O&M	11	25,239	0	0	0	25,239	0	0
Power Production Other O&M	11	3,158	0	0	0	3,158	0	0
Subtotal		28,398	0	0	0	28,398	0	0
Purchased Power-KW	1	193,398	193,398	0	0	0	0	0
Purchased Power-KWH	4	183,683	0	0	0	183,683	0	0
Purchased Power-Other	14	38,747	19,873	0	0	18,874	0	0
556-Syst contrl & ld dispatch	14	1,807	927	0	0	880	0	0
Subtotal		417,635	214,197	0	0	203,437	0	0
TRANSMISSION O&M	16	53,832	53,832	0	0	0	0	0
DISTRIBUTION OPER								
580-Supervision	12	2,226	0	1,867	136	0	36	0
581-Load dispatching	12	2,416	0	2,027	148	0	39	0
582-Station	2	3,293	0	3,293	0	0	0	0
583-Overhead lines	2	9,900	0	9,900	0	0	0	0
584-Undergrd lines	2	141	0	141	0	0	0	0
585-Street Lights	9	321	0	0	0	0	0	0
586-Meters	5	4,733	0	0	0	0	4,733	0
587-Cust installations	6	356	0	0	0	0	0	356
588-Misc	12	19,512	0	16,370	1,192	0	314	0
589-Rents	12	18	0	15	1	0	0	0
Subtotal		42,917	0	33,614	1,477	0	5,122	356
DISTRIBUTION MAINT								
590-Maint suprv & engr	12	2,251	0	1,889	138	0	36	0
592-Station equipment	2	22,355	0	22,355	0	0	0	0
593-Overhead lines	2	110,871	0	110,871	0	0	0	0
594-Undergrd lines	2	3,658	0	3,658	0	0	0	0
595-Line transformers	3	1,336	0	0	1,336	0	0	0
596-Maint of St Lights	9	1,270	0	0	0	0	0	0
597-Meters	5	3,587	0	0	0	0	3,587	0
598-Misc	12	368	0	309	22	0	6	0
Subtotal		145,695	0	139,081	1,496	0	3,629	0
CUSTOMER EXPENSES								
901-Supervision-accts	6	1,804	0	0	0	0	0	1,804
902-Meter reading	6	12,427	0	0	0	0	0	12,427
903-Records & collection	6	23,949	0	0	0	0	0	23,949
904-Uncollectibles	8	0	0	0	0	0	0	0
908-Cust assistance	6	4,795	0	0	0	0	0	4,795
909-Info & instruc advertising	6	1,385	0	0	0	0	0	1,385
910-Misc cust svc & info	6	129	0	0	0	0	0	129
912-Demonstrating & selling	6	994	0	0	0	0	0	994
913-Advertising ADM	6	0	0	0	0	0	0	0
Subtotal		45,483	0	0	0	0	0	45,483
ADMINISTRATIVE & GEN								
920-Admin & gen salaries-alloc	13	21,474	3,748	12,737	928	2,544	244	0
920-Admin & gen salaries-Dir	18	20,000	0	0	0	0	0	0
921-Office supplies & exp	13	19,793	3,455	11,740	855	2,345	225	0
923-Outside services	13	8,865	1,547	5,258	383	*1,050*	*101*	*0*
924-Property insurance	13	12,826	2,239	7,608	554	1,519	146	0
925-Injuries & damages	13	11,583	2,022	6,870	500	1,372	132	0
926-Employee pension/benefits	15	94,361	17,642	56,597	974	0	2,868	15,023
928-Regulatory expenses	15	1,776	332	1,065	18	0	54	283
930-Misc general expenses	15	64,588	12,076	38,739	667	0	1,963	10,283
931-Rents	13	0	0	0	0	0	0	0
932-Maint of general plant	17	11,550	2,016	6,851	499	1,368	131	0
Subtotal		266,816	45,076	147,465	5,378	10,199	5,863	25,588

DEPRECIATION EXPENSE								
Production	11	13,064	0	0	0	13,064	0	0
Transmission	16	21,665	21,665	0	0	0	0	0
Distribution	12	133,124	0	111,686	8,134	0	2,140	0
General	17	41,890	7,311	24,847	1,810	4,963	476	0
Subtotal		209,744	28,977	136,533	9,944	18,026	2,616	0
Taxes-Property-Electric Utility	13	23,132	4,037	13,721	999	2,740	263	0
Taxes-other	13	6,148	1,073	3,647	266	728	70	0
Interest on cust deposits	8	3,236	0	0	0	0	0	0
TOTAL EXPENSES		1,243,036	347,192	474,060	19,560	263,529	17,562	71,428

CUSTOMER FACTORS	TOTAL	Residential 01	Sm Comm 05	Pub Auth 06	Lg Power 08	Irrigation 04	St Lts 07
Average No. Customers **	694	541	121	7	5	17	4
Weighting Factors-Plant-meters		1.00	2.00	5.50	5.50	3.50	0.00
Weighting Factors-Plant-svc drp		1.00	1.00	1.00	4.00	1.00	0.00
Weighting Factors-Services		6.00	8.00	8.00	15.00	15.00	1.00
Wgt'd Cust-Plant-Meters	906	541	242	39	28	58	0
Wgt'd Cust-Services	4,594	3,245	966	56	75	249	4
Wgt'd Cust-Plant-Svc drp	705	541	121	7	20	17	0

ALLOCATION FACTORS	AF	TOTAL	Residential 01	Sm Comm 05	Pub Auth 06	Lg Power 08	Irrigation 04	St Lts 07
Demand-CP (Sys 12 CP)	1	1.0000	0.5159	0.1862	0.0295	0.2404	0.0275	0.0004
Demand-Primary (sch peak)	2	1.0000	0.5338	0.1543	0.0223	0.2248	0.0635	0.0013
Demand-Secondary (MCDxDcf)	3	1.0000	0.7303	0.0981	0.0155	0.1284	0.0272	0.0005
Energy (MWH)	4	1.0000	0.4658	0.1634	0.0220	0.3176	0.0297	0.0014
Customer-Plant-Meters (calc)	5	1.0000	0.5967	0.2665	0.0425	0.0303	0.0640	0.0000
Customer-Services (calc)	6	1.0000	0.7062	0.2103	0.0122	0.0163	0.0541	0.0009
Cust-Plant-Svc drops (Calc)	7	1.0000	0.7669	0.1713	0.0099	0.0284	0.0235	0.0000
Direct-Lighting	9	1.0000	0.0000	0.0000	0.0000	0.0000	0.0000	1.0000
Average customers	10	1.0000	0.7791	0.1740	0.0101	0.0072	0.0239	0.0058
Deposits	11	1.0000	0.8624	0.1342	0.0000	0.0000	0.0034	0.0000

REVENUES	AF	TOTAL	Residential 01	Sm Comm 05	Pub Auth 06	Lg Power 08	Irrigation 04	St Lts 07
REVENUES-Rate **	DIR	1,377,561	625,697	249,012	34,225	421,657	42,293	4,677
REVENUE CREDITS								
450-Penalties	10	1,873	1,459	326	19	13	45	11
451-Conn,Disc & ret ck fees	10	3,614	2,816	629	36	26	86	21
454-Rents fr electric property	2	2,573	1,373	397	57	578	163	3
456-other electric revenue	2	6,417	3,425	990	143	1,443	408	8
456.01-wheeling revenue	1	45,144	23,288	8,407	1,333	10,853	1,243	19
Subtotal		59,621	32,362	10,748	1,589	12,913	1,946	62
TOTAL REVENUES		1,437,182	658,059	259,760	35,814	434,570	44,239	4,739

ALLOCATE EXPENSES	AF	TOTAL	Residential 01	Sm Comm 05	Pub Auth 06	Lg Power 08	Irrigation 04	St Lts 07
Demand-CP	1	347,192	179,106	64,655	10,252	83,467	9,563	149
-Primary	2	474,060	253,043	73,144	10,586	106,571	30,119	596
-Secondary	3	19,560	14,284	1,920	304	2,511	531	11
Total Demand		840,812	446,432	139,719	21,141	192,549	40,214	756
Energy	4	263,529	122,751	43,069	5,808	83,707	7,835	358
Customer-Plant-Meters	5	17,562	10,478	4,680	746	533	1,125	0
-Services	6	71,428	50,443	15,019	871	1,166	3,867	62
-Plant-Services	7	23,064	17,688	3,950	229	654	542	0
Total Customer		112,053	78,610	23,648	1,846	2,353	5,535	62
Direct-Cust Deposits	10	3,236	2,521	563	33	23	77	19
Direct-Lighting	9	3,406	0	0	0	0	0	3,406
Direct-Impact Fees	10	0	0	0	0	0	0	0
Direct-Lg Pwr 08	DIR	20,000	0	0	0	20,000	0	0
TOTAL EXPENSES		1,243,036	650,315	207,000	28,827	298,633	53,661	4,601
NET OPER INCOME		194,146	7,744	52,761	6,987	135,938	-9,422	138

ALLOCATE RATE BASE	AF	TOTAL	Residential 01	Sm Comm 05	Pub Auth 06	Lg Power 08	Irrigation 04	St Lts 07
Demand-CP	1	553,323	285,442	103,041	16,338	133,023	15,241	238
-Primary	2	1,941,763	1,036,473	299,601	43,360	436,519	123,370	2,441
-Secondary	3	139,574	101,925	13,698	2,169	17,915	3,792	75
Total Demand		2,634,660	1,423,839	416,341	61,866	587,457	142,403	2,754
Energy	4	397,041	184,941	64,890	8,750	126,116	11,804	540
Customer-Plant-Meters	5	38,244	22,819	10,191	1,625	1,160	2,449	0
-Services	6	8,806	6,219	1,852	107	144	477	8
-Plant-Services	7	183,839	140,992	31,484	1,825	5,215	4,324	0
Total Customer		230,889	170,029	43,526	3,557	6,519	7,250	8
Direct-Cust Deposits	11	-54,869	-47,319	-7,361	0	0	-189	0
Direct-Lighting	9	7,695	0	0	0	0	0	7,695
Direct-Impact Fees	*10*	*0*	*0*	*0*	*0*	*0*	*0*	*0*
Direct-Lg Pwr 08	DIR	2,466	0	0	0	2,466	0	0
TOTAL RATE BASE		3,217,881	1,731,490	517,396	74,173	722,557	161,268	10,996
% Return on Rate Base		6.033%	0.45%	10.20%	9.42%	18.81%	-5.84%	1.26%

	TOTAL	Residential 01	Sm Comm 05	Pub Auth 06	Lg Power 08	Irrigation 04	St Lts 07
Total Return ($) with Target ROR =	**5.67%**						
Demand Total	149,624	80,785	23,622	3,510	33,471	8,080	156
---Coincident Peak (CP)	31,394	16,195	5,846	927	7,547	865	14
---Primary	110,310	58,807	16,999	2,460	24,907	7,000	138
---Secondary	7,919	5,783	777	123	1,016	215	4
Energy Total	22,527	10,493	3,682	496	7,155	670	31
Customer Total	10,423	6,962	2,052	202	370	401	437
SUBTOTAL =	182,574	98,240	29,356	4,208	40,996	9,150	624
Total Expenses							
Demand Total	860,812	446,432	139,719	21,141	212,549	40,214	756
---Coincident Peak (CP)	347,192	179,106	64,655	10,252	83,467	9,563	149
---Primary	494,060	253,043	73,144	10,586	126,571	30,119	596
---Secondary	19,560	14,284	1,920	304	2,511	531	11
Energy Total	263,529	122,751	43,069	5,808	83,707	7,835	358
Customer Total	118,695	81,131	24,211	1,878	2,376	5,612	3,487
SUBTOTAL =	1,243,036	650,315	207,000	28,827	298,633	53,661	4,601
Total Revenue Credits							
Demand Total	54,134	28,087	9,794	1,534	12,874	1,815	31
---Coincident Peak (CP)	45,144	23,288	8,407	1,333	10,853	1,243	19
---Primary	8,990	4,799	1,387	201	2,021	571	11
---Secondary	0	0	0	0	0	0	0
Energy Total	0	0	0	0	0	0	0
Customer Total	5,487	4,275	955	55	40	131	32
SUBTOTAL =	59,621	32,362	10,748	1,589	12,913	1,946	62
Total COS (Return+Exp-Rev Credits)							
Demand Total	956,302	499,131	153,547	23,118	233,146	46,479	881
---Coincident Peak (CP)	333,443	172,013	62,095	9,846	80,162	9,184	143
---Primary	595,380	307,051	88,756	12,845	149,457	36,548	723
---Secondary	27,479	20,067	2,697	427	3,527	747	15
Energy Total	286,056	133,244	46,751	6,304	90,863	8,505	389
Customer Total	123,632	83,818	25,308	2,025	2,707	5,881	3,892
Total Cost-of-Service	1,365,990	716,193	225,607	31,447	326,715	60,865	5,163
Total Sales Revenues	1,377,561	625,697	249,012	34,225	421,657	42,293	4,677
Deficit	-11,571	90,496	-23,405	-2,778	-94,942	18,572	486
% Rate Increase Required	**-0.84%**	**14.46%**	**-9.40%**	**-8.12%**	**-22.52%**	**43.91%**	**10.39%**
ANNUAL BILLING UNITS							
Cust-months or lamp-months	8,857	6,489	1,449	84	60	199	576
KWH (@ meter)	17,102,033	7,889,400	2,768,124	373,265	5,544,645	503,559	23,040
KW (MCD @ meter)	97,948	73,900	10,674	1,731	9,196	2,379	67
KWH summer peak hours		1,885,383	795,017	60,871	1,417,693	216,690	
KWH summer off peak hours		1,148,080	484,115	37,066	863,287	131,950	
KWH winter peak hours		*3,717,940*	*1,140,044*	*210,804*	*2,498,820*	*118,613*	
KWH winter off peak hours		1,137,997	348,948	64,524	764,845	36,306	
Total kwh		7,889,400	2,768,124	373,265	5,544,645	503,559	

AVERAGE UNIT COST OF SERVICE

Cust-$/Cust/mo or Tot $/lamp/mo	13.96	12.92	17.47	24.10	45.11	29.55	8.96
Energy--Cents/kwh	1.67	1.69	1.69	1.69	1.64	1.69	
Demand--$/Kw	9.76	6.75	14.39	13.36	25.35	19.54	
Demand CP--$/kw	3.40	2.33	5.82	5.69	8.72	3.86	
Demand Pri--$/kw	6.08	4.15	8.32	7.42	16.25	15.36	
Demand Sec--$/kw	0.28	0.27	0.25	0.25	0.38	0.31	
Demand CP--Cents/kwh	1.95	2.18	2.24	2.64	1.45	1.82	
Demand Pri--Cents/kwh	3.48	3.89	3.21	3.44	2.70	7.26	
Demand Sec--Cents/kwh	0.16	0.25	0.10	0.11	0.06	0.15	
Demand+Energy**(Avg)**-Cents/kwh		8.02	7.24	7.88	5.84	10.92	
Demand+Energy**(Peak)**-Cents/kwh		11.29	10.35	10.83	8.27	16.40	
Demand+Energy**(Off Peak**)-Cents/kwh		5.84	4.99	5.24	4.40	9.10	
Unit COS with flat cents/Kwh	7.99	9.08	8.15	8.42	5.89	12.09	22.41

Cost of Service Summary With existing debt **Year End 12-31-08**

	Earned % Return on Rate Base	**ROR Index No.**	**% Rate Increase Required for ROR of 5.67%**
Residential 01	0.45%	0.07	14.46%
Small Commercial 05	10.20%	1.69	-9.40%
Public Authorities 06	9.42%	1.56	-8.12%
Large Power 08	18.81%	3.12	-22.52%
Irrigation 04	-5.84%	-0.97	43.91%
Street & Security Lights 07	1.26%	0.21	10.39%
TOTAL ARIZONA	6.03%	1.00	-0.84%

** INPUT VALUES

AUG	SEP	OCT	NOV	DEC	TOTAL	
733,055	653,382	548,183	512,162	644,332	7,889,400	
813,603	725,175	608,417	568,438	715,131	8,756,282	
0.1250	*0.1130*	0.1200	0.1140	*0.1650*	*0.149*	avg
7,882	8,031	6,140	6,240	5,249	73,900	
0.260	0.235	0.300	0.316	0.301		
2,049	1,887	1,842	1,972	1,580	21,633	
2,371	2,183	2,131	2,281	1,828	25,029	
0.594	0.425	0.600	0.702	0.734		
1,408	928	1,279	1,601	1,342	15,581	

AUG	SEP	OCT	NOV	DEC	TOTAL	
285,545	260,227	253,329	209,163	180,154	2,768,124	
316,920	288,821	281,165	232,146	199,949	3,072,284	
0.3814	0.3584	0.3564	0.3397	0.2914	0.36	avg
1,006	1,008	955	855	831	10,674	
0.685	0.476	0.542	0.702	0.440		
689	480	518	600	366	6,021	
798	555	599	695	423	6,966	
0.820	0.700	0.744	0.858	0.479		
654	389	446	596	203	5,624	

AUG	SEP	OCT	NOV	DEC	TOTAL	
21,358	27,119	26,555	23,669	31,821	373,265	
23,705	30,099	29,473	26,270	35,317	414,279	
0.1971	0.2336	0.2792	0.2366	0.2635	0.293	avg
146	161	128	139	162	1,731	
0.685	0.476	0.542	0.702	0.440		
100	77	69	98	71	965	
115	89	80	113	83	1,117	
0.820	0.700	0.744	0.858	0.479		
95	62	60	97	40	892	

AUG	SEP	OCT	NOV	DEC	TOTAL	
417,755	432,235	469,645	641,610	820,925	5,544,645	
449,887	465,481	505,768	690,960	884,067	5,971,114	
0.7734	0.6286	0.4707	1.1535	1.4712	0.869	avg
726	955	1,341	773	750	9,196	
0.700	0.760	0.772	0.816	0.887		
508	726	1,035	630	665	7,162	
570	815	1,162	708	747	8,038	
0.875	0.885	0.929	0.900	0.900		
499	721	1,080	637	672	7,261	

AUG	SEP	OCT	NOV	DEC	TOTAL	
60,937	56,713	44,949	43,954	10,715	503,559	
67,633	62,945	49,888	48,784	11,892	558,890	
0.3083	0.2775	0.2765	0.2639	0.0719	0.26	avg
266	284	219	231	200	2,379	
0.891	1.000	0.061	0.161	0.323		
237	284	13	37	65	1,493	
274	328	15	43	75	1,727	
0.343	0.332	0.799	0.813	0.267		
94	109	12	35	20	832	

AUG	SEP	OCT	NOV	DEC	TOTAL	
1,920	1,920	1,920	1,920	1,920	23,040	
2,131	2,131	2,131	2,131	2,131	25,572	
0.4595	0.4748	0.4595	0.4748	0.4595	0.47	avg
6	6	6	6	6	67	
1	1	1	1	1		
6	6	6	6	6	67	
6	6	6	6	6	78	
0	0	0	0	1		
0	0	0	0	6	13	

2,750	2,209	2,876	2,966	2,282	30,203

CUST-PLT-S	DIR-Deposits	DIR-Lighting	DIR-Impact	DIR-Lg Pwr 08
1				
	1			
		1		
			1	
0.00000	0.00000	0.00000	0.00000	0.00000
0.08063	0.00000	0.00324	0.00000	0.00000
0.05700	*0.00000*	*0.00229*	*0.00000*	*0.00000*
0.00000	0.00000	0.00000	0.00000	0.00000
0.00750	0.00000	0.00583	0.00000	0.00000
0	0	0	0	0
0.05700	0.00000	0.00229	0.00000	0.00000
				1

CUST-PLT-S	DIR-Deposits	DIR-Lighting	DIR-Impact	DIR-Lg Pwr 08	checksum
0	0	0	0	0	0
					0
0	0	0	0	0	0
					0
					0
0	0	0	0	0	0
0	0	0	0	0	0
0	0	0	0	0	0
0	0	0	0	0	0
0	0	0	0	0	0
0	0	0	0	0	0
0	0	0	0	0	0
277,242	0	0	0	0	0
0	0	0	0	0	0
0	0	3,038	0	0	0
0	0	8,105	0	0	0
277,242	0	11,143	0	0	0
					0
50,261	0	2,020	0	0	0
327,503	0	13,163	0	0	0
					0
0	0	0	0	0	0
15,671	0	630	0	0	0
303	0	12	0	0	0
1,226	399	355	0	2,466	0
17,200	399	997	0	2,466	0
					0
0	0	0	0	0	0
0	0	0	0	0	0
136,485	0	5,486	0	0	0
24,379	0	980	0	0	0
160,864	0	6,466	0	0	0
					0
0	0	0	0	0	0
					0
0	55,268	0	0	0	0
					0
183,839	-54,869	7,695	0	2,466	0
					0

CUST-PLT-S	DIR-Deposits	DIR-Lighting	DIR-Impact	DIR-Lg Pwr 08	
					0
					0
					0
0	0	0	0	0	0
0	0	0	0	0	0
0	0	0	0	0	0
0	0	0	0	0	0
0	0	0	0	0	0
0	0	0	0	0	0
0	0	0	0	0	0
0	0	0	0	0	0
					0
0	0	0	0	0	0
					0
					0
179	0	7	0	0	0
195	0	8	0	0	0
0	0	0	0	0	0
0	0	0	0	0	0
0	0	0	0	0	0
0	0	321	0	0	0
0	0	0	0	0	0
0	0	0	0	0	0
1,573	0	63	0	0	0
1	0	0	0	0	0
1,949	0	399	0	0	0
					0
182	0	7	0	0	0
0	0	0	0	0	0
0	0	0	0	0	0
0	0	0	0	0	0
0	0	0	0	0	0
0	0	1,270	0	0	0
0	0	0	0	0	0
30	0	1	0	0	0
211	0	1,279	0	0	0
					0
0	0	0	0	0	0
0	0	0	0	0	0
0	0	0	0	0	0
0	0	0	0	0	0
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0	0	0	0	0	0
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0	0	0	0	0	0
0	0	0	0	0	0
0	0	0	0	0	0
					0
					0
1,224	0	49	0	0	0
0	0	0	0	20,000	0
1,128	0	45	0	0	0
505	0	20	0	0	0
731	0	29	0	0	0
660	0	27	0	0	0
708	0	550	0	0	0
13	0	10	0	0	0
485	0	376	0	0	0
0	0	0	0	0	0
658	0	26	0	0	0
6,113	0	1,134	0	20,000	0

					0
					0
0	0	0	0	0	0
0	0	0	0	0	0
10,734	0	431	0	0	0
2,388	0	96	0	0	0
13,121	0	527	0	0	0
					0
1,319	0	53	0	0	0
350	0	14	0	0	0
0	3,236	0	0	0	0
					0
23,064	3,236	3,406	0	20,000	0
					0
					0
					0

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Garkane Energy Current Tariff Prices (August 1, 2008) vs 2008 Cost of Service
With existing debt

UTAH	Residential21	Irrigation 24	Sm Comm 25	Comm 28	Municipal 29	Fed Gov 32	ExLgPwr15
Cust Chrg - Price ($/mon)	14.00	25.00	15.00	30.00	30.00	27.00	100.00
Cost of service	14.37	38.32	21.81	46.93	46.82	31.16	270.44
Energy - Price (cents/Kwh)	6.50	5.50	5.50	5.50	7.00	7.80	5.00
Second block price	4.50	4.50	4.50		5.00		6.70
Cost of service	8.56	1.69	1.69	1.69	1.69	1.69	1.64
Demand - Price ($/Kw)		5.50	5.50	5.50	6.75	8.00	6.05
Cost of service		23.08	12.45	17.38	15.56	19.56	20.21

UTAH - Kanab	K-Res 21	K-GS1 25	K-GS2 28	K-Fed G 32
Cust Chrg - Price ($/mon)	14.00	15.00	30.00	27.00
Cost of service	14.38	21.82	46.82	31.16
Energy - Price (cents/Kwh)	7.10	6.10	6.10	8.40
Second block price	5.10	5.10		
Cost of service	7.81	1.69	1.65	1.69
Demand - Price ($/Kw)		4.75	5.50	8.00
Cost of service		12.20	16.42	50.34

UTAH - Lighting	UT 100 watt	UT 400 watt	K 100 watt	K 250 watt	K 400 watt
Lighting - Price ($/lamp/mon)	7.65	17.00	8.15	13.75	19.00
Cost of service	5.78	11.61	6.39	9.26	12.13

ARIZONA	Residential 01	Sm Comm 05	Pub Auth 06	Lg Power 08	Irrigation 04	AZ 100 watt
Cust Chrg - Price ($)	12.50	12.50	12.50	20.00	75.00	8.12
Cost of service	12.92	17.47	24.10	45.11	354.65	8.96
Energy - Price (cents/Kwh)	6.907	5.845	5.845	6.115	5.723	
Cost of service	8.02	1.69	1.69	1.64	1.69	
Demand - Price ($/Kw)		6.37	6.37	6.37	5.31	
Cost of service		14.39	13.36	25.35	19.54	

Garkane Energy Current Tariff Prices (August 1, 2008) vs 2008 Consolidated **Cost of Service**
With existing debt

UTAH	Residential21	Irrigation 24	Sm Comm 25	Comm 28	Municipal 29	Fed Gov 32	ExLgPwr15
Cust Chrg - Price ($/mon)	14.00	25.00	15.00	30.00	30.00	27.00	100.00
Cost of service (consolidated)	14.37	38.32	21.81	46.91	46.82	31.16	270.44
Energy - Price (cents/Kwh)	6.50	5.50	5.50	5.50	7.00	7.80	5.00
Second block price	4.50	4.50	4.50		5.00		6.70
Cost of service (consolidated)	8.44	1.69	1.69	1.68	1.69	1.69	1.64
Demand - Price ($/Kw)		5.50	5.50	5.50	6.75	8.00	6.05
Cost of service (consolidated)		23.08	12.37	17.22	15.56	24.01	20.21

UTAH - Kanab	K-Res 21	K-GS1 25	K-GS2 28	K-Fed G 32
Cust Chrg - Price ($/mon)	14.00	15.00	30.00	27.00
Cost of service (consolidated)	14.37	21.81	46.91	31.16
Energy - Price (cents/Kwh)	7.10	6.10	6.10	8.40
Second block price	5.10	5.10		
Cost of service (consolidated)	8.44	1.69	1.68	1.69
Demand - Price ($/Kw)		4.75	5.50	8.00
Cost of service (consolidated)		12.37	17.22	24.01

UTAH - Lighting	UT 100 watt	UT 400 watt	K 100 watt	K 250 watt	K 400 watt
Lighting - Price ($/lamp/mon)	7.65	17.00	8.15	13.75	19.00
Cost of service (consolidated)	5.88	11.69	5.88	8.78	11.69

ARIZONA	Residential 01	Sm Comm 05	Pub Auth 06	Lg Power 08	Irrigation 04	AZ 100 watt
Cust Chrg - Price ($)	12.50	12.50	12.50	20.00	75.00	8.12
Cost of service	12.92	17.47	24.10	45.11	354.65	8.96
Energy - Price (cents/Kwh)	6.907	5.845	5.845	6.115	5.723	
Cost of service	8.02	1.69	1.69	1.64	1.69	
Demand - Price ($/Kw)		6.37	6.37	6.37	5.31	
Cost of service		14.39	13.36	25.35	19.54	

	Energy [illegible]				Energy SALES (kwh) @ Meters				Losses		Garkane @ Deseret Syst Peak (CP)			Garkane System Peak		
	wapa/dg&t	Boulder Plt	CoGen	System	Arizona	Utah	Co. Use	Total	kwh	%				Kw	Time	Date
Jan	20,891,460	2,390,412	0	23,281,872	1,545,817	19,512,660	129,967	21,188,444	2,093,428	8.99%	44,685	8:00 AM	17-Jan-08	41,821	8:00 AM	17-Jan-08
Feb	17,795,666	1,991,657	0	19,787,323	1,540,089	19,292,068	118,534	20,950,691	-1,163,368	-5.88%	41,040	8:00 AM	5-Feb-08	38,137	8:00 AM	7-Feb-08
Mar	16,133,096	2,144,072	0	18,277,168	1,197,250	15,008,482	73,387	16,279,119	1,998,049	10.93%	36,719	8:00 AM	6-Mar-08	35,876	8:00 AM	5-Mar-08
Apr	13,999,356	2,015,708	0	16,015,064	1,302,199	13,843,125	61,437	15,206,761	808,303	5.05%	33,515	9:00 AM	1-Apr-08	30,727	8:00 AM	10-Apr-08
May	13,604,046	2,588,366	199,600	16,392,012	1,341,064	13,714,272	73,167	15,128,503	1,263,509	7.71%	31,186	6:00 PM	19-May-08	27,970	10:00 PM	23-May-08
June	14,228,767	2,032,611	69,360	16,330,738	1,216,928	12,970,790	134,644	14,322,362	2,008,376	12.30%	30,751	4:00 PM	30-Jun-08	30,181	7:00 PM	28-Jun-08
July	16,099,913	2,069,338	0	18,169,251	1,539,594	13,929,168	47,693	15,516,455	2,652,796	14.60%	31,950	6:00 PM	10-Jul-08	32,319	7:00 PM	10-Jul-08
Aug	15,626,923	1,836,102	0	17,463,025	1,520,570	15,058,615	36,748	16,615,933	847,092	4.85%	31,846	5:00 PM	14-Aug-08	29,819	6:00 PM	1-Aug-08
Sept	13,327,678	1,721,170	0	15,048,848	1,431,596	13,423,949	49,716	14,905,261	143,587	0.95%	26,438	6:00 PM	7-Sep-08	29,397	11:00 AM	1-Sep-08
Oct	14,154,640	1,776,667	0	15,931,307	1,344,581	12,488,500	48,022	13,881,103	2,050,204	12.87%	34,036	5:00 PM	1-Oct-08	31,185	8:00 AM	13-Oct-08
Nov	14,569,855	1,816,027	11,680	16,397,562	1,432,478	12,649,318	56,900	14,138,696	2,258,866	13.78%	32,644	8:00 AM	24-Nov-08	33,838	8:00 AM	6-Nov-08
Dec	20,205,417	1,897,072	14,640	22,117,129	1,689,867	15,062,838	54,922	16,807,627	5,309,502	24.01%	40,148	7:00 PM	15-Dec-08	42,237	9:00 AM	27-Dec-08
Total	190,636,817	24,279,202	295,280	215,211,299	17,102,033	176,953,785	885,137	194,940,955	20,270,344	9.42%	414,958			403,507		

Source: Stan Chappell, Garkane Energy

LIGHTING COINCIDENT FACTORS

	[illegible]	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Time of System CP	8:00 AM	8:00 AM	8:00 AM	9:00 AM	6:00 PM	4:00 PM	6:00 PM	5:00 PM	6:00 PM	5:00 PM	8:00 AM	7:00 PM
Day of System CP	17-Jan-08	5-Feb-08	6-Mar-08	1-Apr-08	19-May-08	30-Jun-08	10-Jul-08	14-Aug-08	7-Sep-08	1-Oct-08	24-Nov-08	15-Dec-08
St. Lights on/off	ON	no	no	no	no	no	no	no	no	no	no	ON
Lighting System CF	1	0	0	0	0	0	0	0	0	0	0	1

SUNRISE-SUNSET ANALYSIS

ALL MOUNTAIN TIMES

Deseret System Peak		SLC sunrise am	SLC sunset pm	PHX sunrise am	PHX sunset pm	Lts On ?
8:00 AM	17-Jan-08	7:49		7:32		ON
8:00 AM	5-Feb-08	7:34		7:22		no
8:00 AM	6-Mar-08	6:53		6:51		no
9:00 AM	1-Apr-08	7:10		7:15		no
6:00 PM	19-May-08		8:42		8:25	no
4:00 PM	30-Jun-08		9:03		8:42	no
6:00 PM	10-Jul-08		9:00		8:41	no
5:00 PM	14-Aug-08		8:26		8:15	no
6:00 PM	7-Sep-08		7:49		7:45	no
5:00 PM	1-Oct-08		7:09		7:12	no
8:00 AM	24-Nov-08	7:25		7:09		no
7:00 PM	15-Dec-08		5:01		5:22	ON

Assume light photocells operate 30 minutes after sunrise and 30 minutes before sunset

Source: Sunrise & Sunset times from: www.timeanddate.com

UTAH 2008 CUSTOMER DATA

Garkane Energy 2008 UTAH KWH @ meter (from billing records)

Rate Sched	JAN	FEB	MAR	APR	MAY	JUNE	JULY	AUG	SEPT	OCT	NOV	DEC	TOTAL
Residential 21	9,424,375	9,265,416	6,848,273	5,932,588	5,114,243	4,393,761	4,248,240	4,903,944	4,292,043	4,370,937	5,061,324	6,956,014	70,811,158
Irrigation 24	16,718	14,942	19,570	28,908	152,974	815,461	732,908	798,461	658,445	483,900	78,228	32,829	3,833,344
Sm Comm GS1 25	2,004,197	2,090,128	1,711,244	1,714,003	1,853,462	1,814,965	1,986,401	2,224,262	1,892,673	1,740,600	1,621,219	1,661,761	22,314,915
St & Sec Lts 27	40,280	40,280	40,280	40,280	40,280	40,280	40,280	40,280	40,280	40,280	40,280	40,280	483,360
Comm GS2 28	2,304,199	2,486,832	1,942,311	1,882,179	2,179,220	1,722,848	1,780,710	2,025,066	1,752,822	1,745,989	1,889,119	1,679,771	23,391,066
Municipal Culinary 29	21,723	22,340	24,419	29,714	45,228	54,892	67,173	69,390	54,167	45,720	29,448	20,131	484,345
Fed Gov GS3 32	157,060	181,579	122,758	134,558	184,663	157,127	144,242	162,405	143,327	122,123	122,063	127,696	1,759,601
Extra Large Power 15	2,236,000	1,922,000	2,078,000	1,818,000	2,007,000	1,801,000	2,213,000	1,807,000	2,036,000	2,000,000	1,607,000	2,133,000	23,658,000
Kanab-residential 21	1,669,912	1,629,871	1,042,828	968,261	794,855	772,774	997,897	1,119,149	869,758	785,581	879,153	1,139,524	12,669,563
Kanab-GS1 25	1,067,625	1,055,524	740,565	787,528	821,110	874,983	1,074,132	1,185,348	896,003	819,271	794,515	780,783	10,897,387
Kanab-St/Sec Lts 27	17,560	17,560	17,560	17,560	17,560	17,560	17,560	17,560	17,560	17,560	17,560	17,560	210,720
Kanab-GS2 28	530,060	542,820	404,260	472,820	484,880	486,540	600,780	676,740	555,820	498,240	493,180	458,480	6,204,620
Kanab-Fed Gov 32	22,898	22,763	16,081	16,433	18,362	18,186	24,254	27,168	19,485	17,519	16,936	15,716	235,801
TOTAL	19,512,607	19,292,055	15,008,149	13,842,832	13,713,837	12,970,377	13,927,577	15,056,773	13,228,383	12,687,720	12,650,025	15,063,545	176,953,880

Source: Stan Chappell, Garkane Energy Cooperative

Garkane Energy 2007 UTAH DEMAND REVENUE ($) (from billing records)

Rate Sched	JAN	FEB	MAR	APR	MAY	JUNE	JULY	AUG	SEPT	OCT	NOV	DEC	TOTAL	AVE
Irrigation 24	313	305	426	1,296	3,289	8,243	8,600	8,665	8,348	6,934	1,357	622	48,398	4,033
SmComm GS1 25	30,485	30,163	29,754	32,199	34,213	35,057	35,840	35,192	34,848	36,149	33,499	32,242	399,639	33,303
Comm GS2 28	31,268	31,903	29,615	31,703	33,238	31,564	28,214	28,245	29,806	33,534	32,982	32,116	374,187	31,182
Municipal Culinary 29	654	780	1,170	858	1,122	978	1,338	1,056	1,038	1,284	1,512	1,572	13,362	1,114
Fed Gov GS3 32	3,129	3,220	3,276	3,514	3,955	4,312	4,200	3,920	3,773	3,801	3,094	3,773	43,967	3,664
Extra Large Power 15	17,200	17,109	17,188	17,224	17,140	17,291	17,158	17,140	16,976	17,073	17,025	17,079	205,603	17,134
Kanab-GS1 25	15,086	14,412	14,790	15,038	15,982	16,047	16,891	16,339	16,121	14,694	14,325	15,177	184,901	15,408
Kanab-GS2 28	5,803	5,672	5,933	5,677	6,290	6,625	6,943	6,890	6,951	5,916	5,559	5,912	74,172	6,181
Kanab-Fed Gov 32	684	672	666	672	504	528	546	534	516	396	414	690	6,822	569
TOTAL	104,622	104,236	102,819	108,181	115,732	120,645	119,729	117,980	118,377	119,781	109,767	109,183	1,351,051	112,588

Source: Stan Chappell, Garkane Energy Cooperative

Garkane Energy 2007 UTAH KW @ meter (calculated by dividing demand revenue by $/kw demand charge for rate schedule)

Rate Sched	JAN	FEB	MAR	APR	MAY	JUNE	JULY	AUG	SEPT	OCT	NOV	DEC	TOTAL	AVE	$/kw	Yr End 8/08 Total
Irrigation 24	72	70	98	298	756	1,895	1,977	1,992	1,919	1,594	312	143	11,126	927	4.35	11,233
SmComm GS1 25	7,008	6,934	6,840	7,402	7,865	8,059	8,239	8,090	8,011	8,310	7,701	7,412	91,871	7,656	4.35	95,808
Comm GS2 28	7,188	7,334	6,808	7,288	7,641	7,256	6,486	6,493	6,852	7,709	7,582	7,383	86,020	7,168	4.35	86,333
Municipal Culinary 29	109	130	195	143	187	163	223	176	173	214	252	262	2,227	186	6.00	2,483
Fed Gov GS3 32	447	460	468	502	565	616	600	560	539	543	442	539	6,281	523	7.00	6,499
Extra Large Power 15	2,843	2,828	2,841	2,847	2,833	2,858	2,836	2,833	2,806	2,822	2,814	2,823	33,984	2,832	6.05	33,660
Kanab-GS1 25	3,468	3,313	3,400	3,457	3,674	3,689	3,883	3,756	3,706	3,378	3,293	3,489	42,506	3,542	4.35	44,590
Kanab-GS2 28	1,334	1,304	1,364	1,305	1,446	1,523	1,596	1,584	1,598	1,360	1,278	1,359	17,051	1,421	4.35	17,077
Kanab-Fed Gov 32	114	112	111	112	84	88	91	89	86	66	69	115	1,137	95	6.00	1,097
TOTAL	22,583	22,485	22,125	23,354	25,051	26,147	25,931	25,573	25,690	25,996	23,743	23,525	292,203	24,350		

Source: Monthly demand charges from Garkane Energy Rate Schedules

Garkane Energy 2008 UTAH Number of CUSTOMERS (from billing records)

Rate Sched	JAN	FEB	MAR	APR	MAY	JUNE	JULY	AUG	SEPT	OCT	NOV	DEC	average
Residential 21	7,792	7,790	7,786	7,789	7,815	7,827	7,839	7,858	7,882	7,881	7,876	7,883	7,835
Irrigation 24	35	34	34	37	169	173	177	177	179	150	54	38	105
Sm Comm GS1 25	1,042	1,046	1,052	1,052	1,052	1,053	1,055	1,066	1,067	1,070	1,074	1,070	1,058
St & Sec Lts 27	23	23	23	23	27	27	27	27	27	27	27	27	26
Comm GS2 28	121	120	122	120	121	121	122	126	124	125	124	124	123
Municipal Culinary 29	11	11	11	11	11	11	11	11	11	11	11	11	11
Fed Gov GS3 32	92	92	92	91	91	91	91	91	91	91	90	90	91
Extra Large Power 15	1	1	1	1	1	1	1	1	1	1	1	1	1
Kanab-residential 21	1,177	1,167	1,173	1,194	1,190	1,200	1,193	1,202	1,189	1,187	1,177	1,176	1,185
Kanab-GS1 25	358	361	360	362	361	363	361	360	362	361	362	362	361
Kanab-St/Sec Lts 27	2	2	2	1	1	3	3	3	3	1	1	1	2
Kanab-GS2 28	15	15	15	15	15	16	15	15	15	15	15	15	15
Kanab-Fed Gov 32	5	5	5	5	5	5	5	5	5	5	5	5	5
Total Customers	10,674	10,667	10,676	10,701	10,859	10,891	10,900	10,942	10,956	10,925	10,817	10,803	10,818

Source: Stan Chappell, Garkane Energy Cooperative

GARKANE ARIZONA/UTAH REVENUES & CUSTOMERS:

Garkane Energy 2008 Rate Revenues

Month	[illegible]	[illegible]	[illegible]
JAN	122,357	1,338,284	1,460,641
FEB	121,490	1,322,442	1,443,932
MAR	100,071	1,105,544	1,205,614
APR	107,052	1,053,795	1,160,847
MAY	113,867	1,075,668	1,189,535
JUNE	101,714	1,014,946	1,116,661
JULY	122,180	1,138,743	1,260,922
AUG	121,114	1,202,010	1,323,123
SEPT	114,919	1,108,050	1,222,969
OCT	111,557	1,078,554	1,190,111
NOV	113,813	1,066,886	1,180,699
DEC	127,427	1,174,356	1,301,783
Total	1,377,561	13,679,278	15,056,838

Source: Stan Chappell, Garkane Energy Cooperative

2008 Average Number of Customers

Month	[illegible]	[illegible]
JAN	10,674	690
FEB	10,667	688
MAR	10,676	689
APR	10,701	691
MAY	10,859	697
JUNE	10,891	695
JULY	10,900	700
AUG	10,942	696
SEPT	10,956	700
OCT	10,925	697
NOV	10,817	695
DEC	10,803	691
Avg # Custs	10,818	694
fraction	0.9397	0.0603

RATE SCHEDULE DATA: (Revenue: projected 2009 based on 8-1-08 rate increase and yr end 8-31-08 billing units)

	Total	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
Rate revenue	14,220,578	5,818,283	285,076	1,908,127	90,668	1,838,355	50,630	217,492	1,519,776	1,046,736	906,875	30,172	477,849	30,539
Deposits (fraction)	1.0000	0.566	0.0052	0.09259	0.0000	0.0813	0.0000	0.0000	0.0000	0.2055	0.04945	0.0000	0.0000	0.0000
Avg # custs/ln transf		1.5	1	1	1	1	1	1	1	1.5	1	1	1	1
Delivery voltage		secondary	secondary	secondary	secondary	secondary	secondary	secondary	primary	secondary	secondary	secondary	secondary	secondary

Source: Stan Chappell, Garkane Energy Cooperative

DEVELOPMENT OF CUSTOMER WEIGHTING FACTORS:

	[illegible]	Seasonal 22	Irrigation 24	Sm Comm 25	St/Sec Lts27	Comm 28	Municipal 29	GS1 ND 31	Fed Gov 32	ExLgPwr15	K-Res 21	K-GS1 25	K-St Lts 27	K-GS2 28	K-GS1 ND31	K-Fed G 32
1. Type of meter	kwh	kwh	kwh & kw	kwh & kw	None	kwh & kw	kwh & kw	kwh	kwh & kw	kwh & kw	kwh	kwh & kw	None	kwh & kw	kwh	kwh & kw
2. # meter reads/bills per yr	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12
3. rel labor-meter reading,billing, svc	6	6	15	8	1	8	8	6	15	60	6	8	1	8	6	15
4. line 3 X line 4	72	72	180	96	12	96	96	72	180	720	72	96	12	96	72	180
5. Relative wgt-services	6.00	6.00	15.00	8.00	1.00	8.00	8.00	6.00	15.00	60.00	6.00	8.00	1.00	8.00	6.00	15.00
6. est cost of metering	100	100	350	200	0	600	600	100	200	4,000	100	200	0	600	100	200
7. Relative wgt-plant- meters	1.00	1.00	3.50	2.00	0.00	6.00	6.00	1.00	2.00	40.00	1.00	2.00	0.00	6.00	1.00	2.00
8. est cost of service drops	1,000	1,000	1,000	1,000	0	4,000	4,000	1,000	1,000	0	1,000	1,000	0	4,000	1,000	1,000
9. Relative wgt-plant- svc drops	1.00	1.00	1.00	1.00	0.00	4.00	4.00	1.00	1.00	0.00	1.00	1.00	0.00	4.00	1.00	1.00

Source: Meter & service drop costs - Mike Avant, Garkane Energy Cooperative

2007 STREET LIGHT DATA:

Type	Lamp Watts	Ballast loss	Tot Ln watts	Burn Hrs	kw/lamp	kwh/year
Sodium Vapor	100	17	117	4,102	0.117	480
Sodium Vapor	250	43	293	4,102	0.293	1,200
Sodium Vapor	400	68	468	4,102	0.468	1,920

Lighting Plant Allocation Factor

	[redacted]	Kanab	rel fixture cost
Avg # 100 watt	951	111	1
Avg # 250 watt	0	32	1
Avg # 400 watt	14	62	5
relative wgt'd cc	1,021	453	
Lt plant AF	0.6927	0.3073	

Source: Relative fixture cost - Mike Avant, Garkane Energy Cooperative

Utah (w/o Kanab)--Number of LAMPS (from billing records)

Lamp watts	JAN	FEB	MAR	APR	MAY	JUNE	JULY	AUG	SEPT	OCT	NOV	DEC	AVE
100	951	951	951	951	951	951	951	951	951	951	951	951	951.0
400	14	14	14	14	14	14	14	14	14	14	14	14	14.0

Kanab--Number of LAMPS (from billing records)

Lamp watts	JAN	FEB	MAR	APR	MAY	JUNE	JULY	AUG	SEPT	OCT	NOV	DEC	AVE
100	111	111	111	111	111	111	111	111	111	111	111	111	111.0
250	32	32	32	32	32	32	32	32	32	32	32	32	32.0
400	62	62	62	62	62	62	62	62	62	62	62	62	62.0

Source: assumed Jan 2006 # of lamps same for all months of 2007

2008 AVERAGE CUSTOMER LOADS

Rate Sched	JAN	FEB	MAR	APR	MAY	JUNE	JULY	AUG	SEPT	OCT	NOV	DEC	Average
Avg kwh usage													
Residential 21	1,209	1,189	880	762	654	561	542	624	545	555	643	882	754
Irrigation 24	478	439	576	781	905	4,714	4,141	4,511	3,678	3,226	1,449	864	2,147
Sm Comm GS1 25	1,923	1,998	1,627	1,629	1,762	1,724	1,883	2,087	1,774	1,627	1,510	1,553	1,758
Comm GS2 28	19,043	20,724	15,921	15,685	18,010	14,238	14,596	16,072	14,136	13,968	15,235	13,547	15,931
Municipal Culinary 29	1,975	2,031	2,220	2,701	4,112	4,990	6,107	6,308	4,924	4,156	2,677	1,830	3,669
Fed Gov GS3 32	1,707	1,974	1,334	1,479	2,029	1,727	1,585	1,785	1,575	1,342	1,356	1,419	1,609
Extra Large Power 15	2,236,000	1,922,000	2,078,000	1,818,000	2,007,000	1,801,000	2,213,000	1,807,000	2,036,000	2,000,000	1,607,000	2,133,000	1,971,500
Kanab-residential 21	1,419	1,397	889	811	668	644	836	931	732	662	747	969	892
Kanab-GS1 25	2,982	2,924	2,057	2,175	2,275	2,410	2,975	3,293	2,475	2,269	2,195	2,157	2,516
Kanab-GS2 28	35,337	36,188	26,951	31,521	32,325	30,409	40,052	45,116	37,055	33,216	32,879	30,565	34,301
Kanab-Fed Gov 32	4,580	4,553	3,216	3,287	3,672	3,637	4,851	5,434	3,897	3,504	3,387	3,143	3,930
Avg kw demand													
Irrigation 24	2	2	3	8	4	11	11	11	11	11	6	4	7
SmComm GS1 25	7	7	7	7	7	8	8	8	8	8	7	7	7
Comm GS2 28	59	61	56	61	63	60	53	52	55	62	61	60	59
Municipal Culinary 29	10	12	18	13	17	15	20	16	16	19	23	24	17
Fed Gov GS3 32	5	5	5	6	6	7	7	6	6	6	5	6	6
Extra Large Power 15	2,843	2,828	2,841	2,847	2,833	2,858	2,836	2,833	2,806	2,822	2,814	2,823	2,832
Kanab-GS1 25	10	9	9	10	10	10	11	10	10	9	9	10	10
Kanab-GS2 28	89	87	91	87	96	95	106	106	107	91	85	91	94
Kanab-Fed Gov 32	23	22	22	22	17	18	18	18	17	13	14	23	19
Avg Load Factor													
Irrigation 24	0.3121	0.3176	0.2684	0.1347	0.2720	0.5977	0.4983	0.5388	0.4766	0.4080	0.3482	0.3086	0.37
SmComm GS1 25	0.3844	0.4486	0.3363	0.3216	0.3167	0.3128	0.3241	0.3695	0.3281	0.2815	0.2924	0.3013	0.33
Comm GS2 28	0.4309	0.5046	0.3835	0.3587	0.3833	0.3298	0.3690	0.4192	0.3553	0.3044	0.3461	0.3058	0.37
Municipal Culinary 29	0.2679	0.2557	0.1683	0.2886	0.3251	0.4677	0.4049	0.5299	0.4349	0.2872	0.1623	0.1033	0.31
Fed Gov GS3 32	0.4723	0.5874	0.3526	0.3723	0.4393	0.3543	0.3231	0.3898	0.3693	0.3023	0.3836	0.3184	0.39
Extra Large Power 15	1.0571	1.0114	0.9831	0.8869	0.9522	0.8752	1.0488	0.8573	1.0078	0.9526	0.7932	1.0156	0.95
Kanab-GS1 25	0.4138	0.4741	0.2928	0.3164	0.3004	0.3294	0.3718	0.4242	0.3358	0.3260	0.3351	0.3008	0.35
Kanab-GS2 28	0.5341	0.6195	0.3984	0.5032	0.4507	0.4437	0.5060	0.5742	0.4831	0.4924	0.5360	0.4534	0.50
Kanab-Fed Gov 32	0.2700	0.3024	0.1947	0.2038	0.2938	0.2870	0.3582	0.4103	0.3147	0.3568	0.3409	0.1837	0.29

Source: Calculated from billing data

ARIZONA 2008 CUSTOMER DATA

Garkane Energy 2008 ARIZONA KWH @ meter (from billing records)

Rate Sched	JAN	FEB	MAR	APR	MAY	JUNE	JULY	AUG	SEPT	OCT	NOV	DEC	TOTAL
Residential 01	945,771	902,532	684,535	618,422	492,834	489,337	664,855	733,055	653,382	548,183	512,162	644,332	7,889,400
SmComm 05	229,765	223,539	187,271	205,771	199,093	244,239	290,028	285,545	260,227	253,329	209,163	180,154	2,768,124
Public Authorities 06	62,635	63,378	38,432	28,838	19,507	11,287	18,666	21,358	27,119	26,555	23,669	31,821	373,265
Large Power 08	300,150	341,950	277,555	411,830	565,960	402,815	462,215	417,755	432,235	469,645	641,610	820,925	5,544,645
Irrigation 04	5,576	6,770	7,537	35,418	61,750	67,330	101,910	60,937	56,713	44,949	43,954	10,715	503,559
St & Sec Lts 07	1,920	1,920	1,920	1,920	1,920	1,920	1,920	1,920	1,920	1,920	1,920	1,920	23,040
TOTAL	1,545,817	1,540,089	1,197,250	1,302,199	1,341,064	1,216,928	1,539,594	1,520,570	1,431,596	1,344,581	1,432,478	1,689,867	17,102,033

Source: Stan Chappell, Garkane Energy Cooperative

Garkane Energy 2007 ARIZONA DEMAND REVENUE ($) (from billing records)

Rate Sched	JAN	FEB	MAR	APR	MAY	JUNE	JULY	AUG	SEPT	OCT	NOV	DEC	TOTAL	AVE
SmComm 05	4,746	4,625	4,656	5,364	5,854	6,517	6,523	6,402	6,415	6,077	5,440	5,287	67,904	5,659
Public Authorities 06	860	930	777	860	771	815	688	834	924	733	796	930	9,918	827
Large Power 08	2,631	2,637	2,784	4,255	6,141	5,555	4,586	4,625	6,083	8,542	4,921	4,778	57,537	4,795
Irrigation 04	271	335	366	1,152	1,211	1,274	1,237	1,317	1,407	1,083	1,147	993	11,794	983
TOTAL	8,507	8,526	8,584	11,631	13,976	14,161	13,034	13,178	14,829	16,435	12,304	11,988	147,153	12,263

Source: Stan Chappell, Garkane Energy Cooperative

Garkane Energy 2007 ARIZONA KW @ meter (calculated by dividing demand revenue by $/kw demand charge for rate schedule)

Rate Sched	JAN	FEB	MAR	APR	MAY	JUNE	JULY	AUG	SEPT	OCT	NOV	DEC	TOTAL	AVE	$/kw	Yr End 8/08 Total
SmComm 05	745	726	731	842	919	1,023	1,024	1,005	1,007	954	854	830	10,660	888	6.37	10,674
Public Authorities 06	135	146	122	135	121	128	108	131	145	115	125	146	1,557	130	6.37	1,731
Large Power 08	413	414	437	668	964	872	720	726	955	1,341	773	750	9,033	753	6.37	12,617
Irrigation 04	51	63	69	217	228	240	233	248	265	204	216	187	2,221	185	5.31	2,379
TOTAL	1,344	1,349	1,359	1,862	2,232	2,263	2,085	2,110	2,372	2,614	1,968	1,913	23,471	1,956		

Source: Monthly $/k demand charge from Garkane Energy Cooperative Rate Schedules

Garkane Energy 2008 ARIZONA Number of CUSTOMERS (from billing records)

Rate Sched	JAN	FEB	MAR	APR	MAY	JUNE	JULY	AUG	SEPT	OCT	NOV	DEC	AVE
Residential 01	543	543	543	541	541	539	542	539	542	539	538	539	541
SmComm 05	119	118	118	118	121	121	122	122	123	123	122	122	121
Public Authorities 06	7	7	7	7	7	7	7	7	7	7	7	7	7
Large Power 08	5	5	5	5	5	5	5	5	5	5	5	5	5
Irrigation 04	12	11	12	16	19	19	20	19	19	19	19	14	17
St & Sec Lts 07	4	4	4	4	4	4	4	4	4	4	4	4	4
Total Meters	690	688	689	691	697	695	700	696	700	697	695	691	694

Source: Stan Chappell, Garkane Energy Cooperative

PEAK HOURS KWH DATA

2008	TOTAL KWH			10a-11p Summer kwh		summer	6a-11p Winter kwh		winter
Rate Sched	Summer	Winter	Total	Peak Hrs	Off Pk Hrs	total	Peak Hrs	Off Pk Hrs	total
Residential 01	3,033,463	4,855,937	7,889,400	1,885,383	1,148,080	3,033,463	3,717,940	1,137,997	4,855,937
SmComm 05	1,279,132	1,488,992	2,768,124	795,017	484,115	1,279,132	1,140,044	348,948	1,488,992
Public Authorities 06	97,937	275,328	373,265	60,871	37,066	97,937	210,804	64,524	275,328
Large Power 08	2,280,980	3,263,665	5,544,645	1,417,693	863,287	2,280,980	2,498,820	764,845	3,263,665
Irrigation 04	348,640	154,919	503,559	216,690	131,950	348,640	118,613	36,306	154,919
TOTAL	7,040,152	10,038,841	17,078,993	4,375,653	2,664,499	7,040,152	7,686,222	2,352,619	10,038,841

Source: Calculated from above kwh data and DGT seasonal hourly load shape data (see file: Billing Units Pk vs Offpk 08)

RATE SCHEDULE DATA: 2008

	Total	Residential 01	SmComm05	PubAuth 06	Lg Power 08	Irrigation 04	St Lights 07
Rate revenue	1,377,561	625,697	249,012	34,225	421,657	42,293	4,677
Deposits (fraction)	1.0000	0.8624	0.1342	0.0000	0.0000	0.0034	0.0000
Avg # custs/ln transf		1.5	1	1	1	1	1
Delivery voltage		secondary	secondary	secondary	pri/sec	secondary	secondary

Source: Stan Chappell, Mike Avant & Marcus Lewis, Garkane Energy Cooperative

DEVELOPMENT OF CUSTOMER WEIGHTING FACTORS:

	[illegible]	SmComm05	Pub Auth 06	LgPower 08	Irrigation 04	St Lts 07
1. Type of meter	kwh	kw & kwh	kw & kwh	kw & kwh	kwh & kw	None
2. # meter reads/bills per yr	12	12	12	12	12	12
3. rel labor-meter reading,billing, svc	6	8	8	15	15	1
4. line 3 X line 4	72	96	96	180	180	12
5. Relative wgt-services	6.00	8.00	8.00	15.00	15.00	1.00
6. est cost of metering	100	200	550	550	350	0
7. Relative wgt-plant-meters	1.00	2.00	5.50	5.50	3.50	0.00
8. est cost of service drops	1,000	1,000	1,000	4,000	1,000	0
9. Relative wgt-plant-svc drops	1.00	1.00	1.00	4.00	1.00	0.00

2008 STREET LIGHT DATA:

Type	Lamp Watts	Ballast loss	Tot Ln watts	Burn Hrs	kw/lamp	kwh/year
Sodium Vapor	100	17	117	4,102	0.117	480

Number of LAMPS (from billing records)

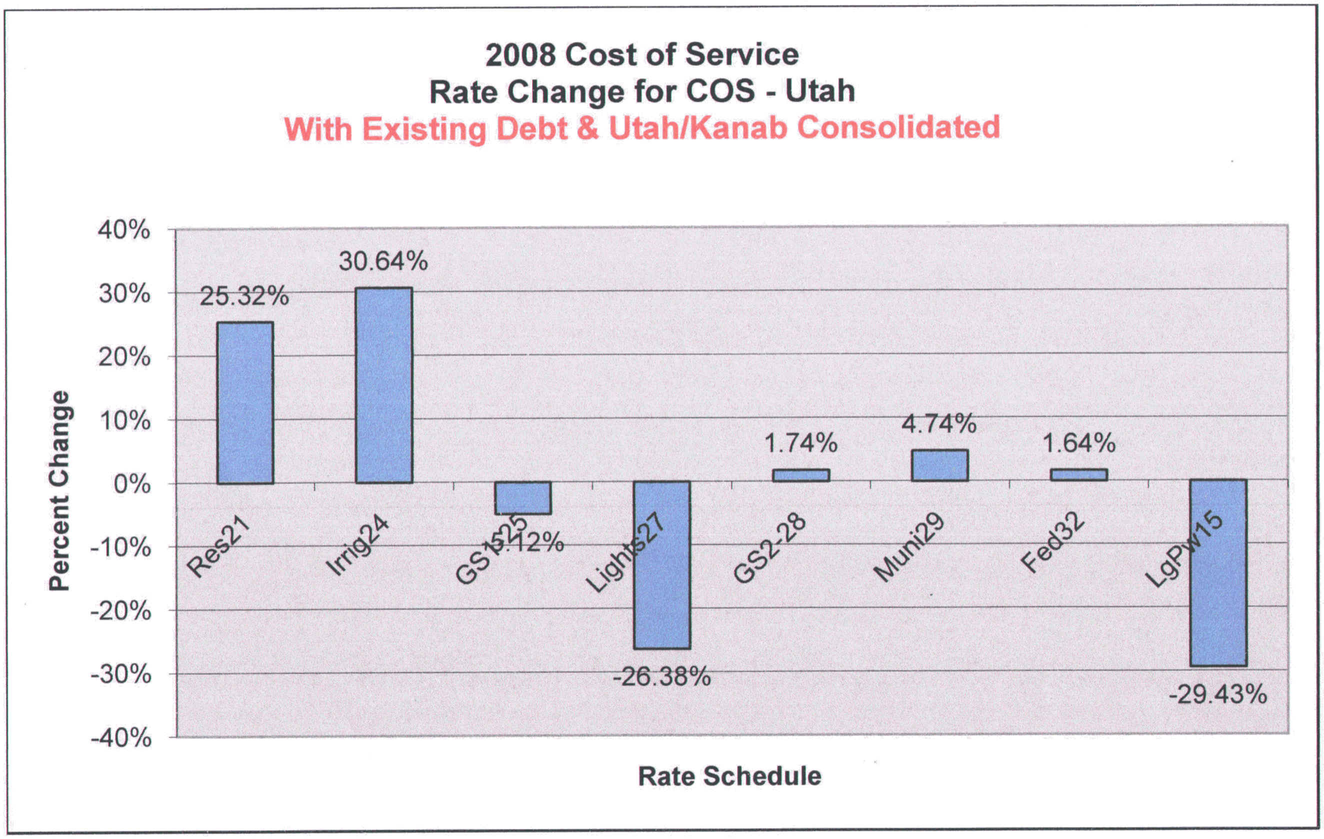
Lamp watts	JAN	FEB	MAR	APR	MAY	JUNE	JULY	AUG	SEPT	OCT	NOV	DEC	AVE
100	48	48	48	48	48	48	48	48	48	48	48	48	48.0

Source: Stan Chappell, Garkane Energy Cooperative

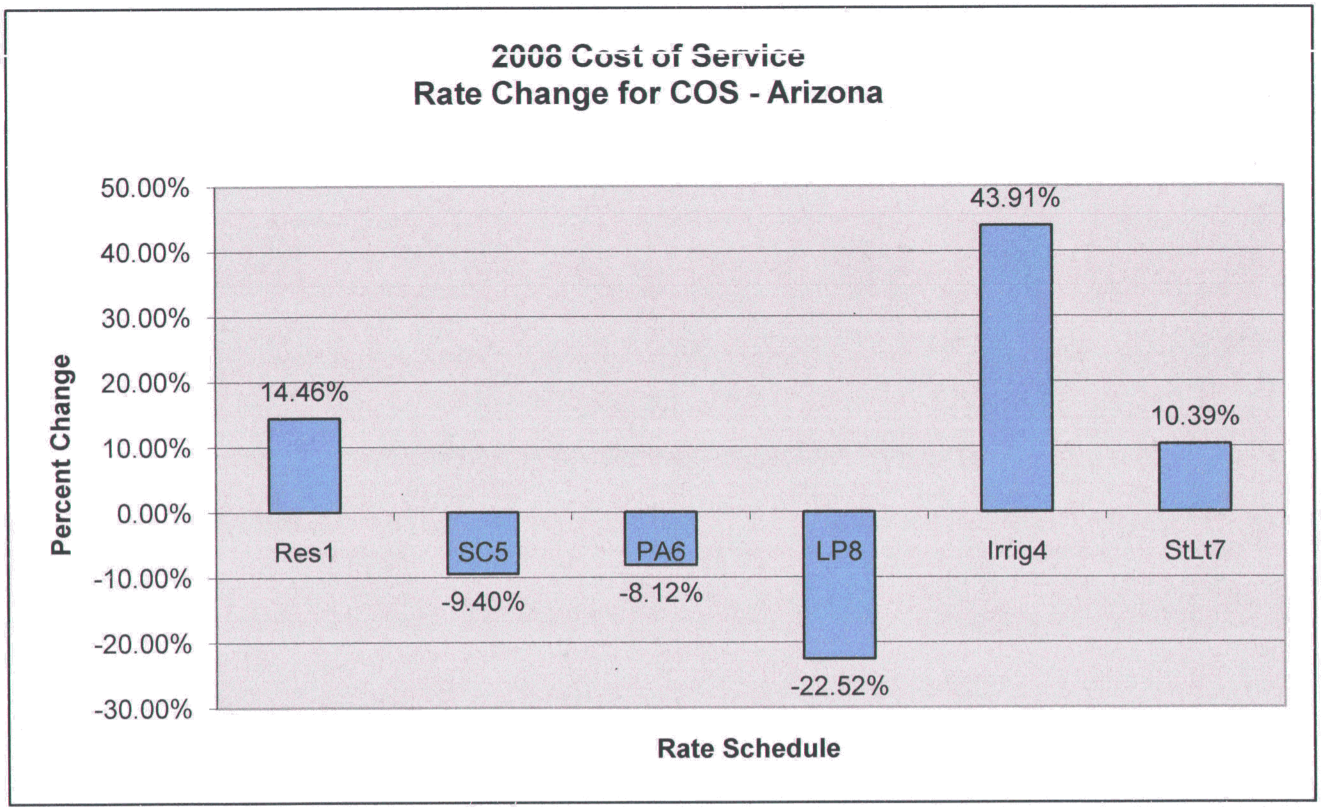
2008 AVERAGE CUSTOMER LOADS

Rate Sched	JAN	FEB	MAR	APR	MAY	JUNE	JULY	AUG	SEPT	OCT	NOV	DEC	Average
Avg kwh usage													
Residential 01	1,742	1,662	1,261	1,143	911	908	1,227	1,360	1,206	1,017	952	1,195	1,215
SmComm 05	1,931	1,894	1,587	1,744	1,645	2,019	2,377	2,341	2,116	2,060	1,714	1,477	1,909
Public Authorities 06	8,948	9,054	5,490	4,120	2,787	1,612	2,667	3,051	3,874	3,794	3,381	4,546	4,444
Large Power 08	60,030	68,390	55,511	82,366	113,192	80,563	92,443	83,551	86,447	93,929	128,322	164,185	92,411
Irrigation 04	465	615	628	2,214	3,250	3,544	5,096	3,207	2,985	2,366	2,313	765	2,287
Avg kw demand													
SmComm 05	6	6	6	7	8	8	8	8	8	8	7	7	7
Public Authorities 06	19	21	17	19	17	18	15	19	21	16	18	21	19
Large Power 08	83	83	87	134	193	174	144	145	191	268	155	150	151
Irrigation 04	4	6	6	14	12	13	12	13	14	11	11	13	11
Avg Load Factor													
SmComm 05	0.4145	0.4582	0.3443	0.3394	0.2912	0.3316	0.3807	0.3819	0.3589	0.3569	0.3402	0.2917	0.36
Public Authorities 06	0.6236	0.6460	0.4234	0.2967	0.2167	0.1225	0.2323	0.2191	0.2598	0.3104	0.2630	0.2929	0.33
Large Power 08	0.9768	1.2291	0.8537	0.8563	0.7891	0.6416	0.8629	0.7734	0.6286	0.4707	1.1535	1.4712	0.89
Irrigation 04	0.1470	0.1599	0.1468	0.2267	0.3640	0.3896	0.5879	0.3303	0.2972	0.2962	0.2826	0.0770	0.28

Source: Calculated from billing data



2008 Cost of Service
Rate Change for COS - Utah
With Existing Debt & Utah/Kanab Consolidated
40%
30%
20%
10%
0%
-10%
-20%
-30%
-40%
Percent Change
25.32%
30.64%
-5.12%
-26.38%
1.74%
4.74%
1.64%
-29.43%
Res21
Irrig24
GS1-25
Lights27
GS2-28
Muni29
Fed32
LgPw15
Rate Schedule



2008 Cost of Service
Rate Change for COS - Arizona
50.00%
40.00%
30.00%
20.00%
10.00%
0.00%
-10.00%
-20.00%
-30.00%
Percent Change
14.46%
-9.40%
-8.12%
-22.52%
43.91%
10.39%
Res1
SC5
PA6
LP8
Irrig4
StLt7
Rate Schedule

Rate Change to get to COS

Utah	% Change
Res21	25.32%
Irrig24	30.64%
GS1-25	-5.12%
Lights27	-26.38%
GS2-28	1.74%
Muni29	4.74%
Fed32	1.64%
LgPw15	-29.43%

Arizona	% Change
Res1	14.46%
SC5	-9.40%
PA6	-8.12%
LP8	-22.52%
Irrig4	43.91%
StLt7	10.39%

AMI Benefit Cost Analysis
L.Alt
4-3-09

GARKANE ENERGY COOPERATIVE
(Docket No. E-01891A-08-0061)

Summary TOU Conversion Benefit/Cost Ratios

Advanced Metering Infrastructure (AMI)

Based on assumed peak load shift= 25%
Based on assumed penetration= 10%

	Per meter Total Incremental Advanced Metering Cost		2008 Annual Fixed Charge Rate		Annualized Cost ($)	Residential Annual Benefit ($)	Residential Benefit/Cost Ratio	For B/C=1 Additional Savings/yr needed	Monthly Cost ($) per Cust	Monthly Benefit ($) per Cust
Alternative 1 (Res only)	523	@	14.03%	=	**73**	**62**	**0.84**	12	6.11	5.13

	Total Company Total Incremental Advanced Metering Cost		2008 Annual Fixed Charge Rate		Annualized Cost ($)	Residential Annual Benefit ($)	Residential Benefit/Cost Ratio	All NL Rates Annual Benefit ($)	All NL Rates Benefit/Cost Ratio	For B/C=1 Additional Savings/yr needed	Monthly Cost ($) per Cust	Monthly Benefit ($) per Cust
Alternative 1 (Res only)	28,234	@	14.03%	=	**3,961**	**3,325**	**0.84**			636	6.11	5.13
Alternative 2 (Res only)	182,948	@	14.03%	=	**25,667**	**3,325**	**0.13**			22,342	39.61	5.13
(with Smart Grid ARRA grant)	111,874	@	14.03%	=	**15,696**	**3,325**	**0.21**			12,371	24.22	5.13
Alternative 2 (all non-lighting)	187,668	@	14.03%	=	**26,330**			**7,207**	**0.27**	19,123	31.34	8.69
(with Smart Grid ARRA grant)	114,234	@	14.03%	=	**16,027**			**7,207**	**0.45**	8,820	19.08	8.69

Alternative 1: Use existing TS1 metering system with compatible meters for TOU customers
(Alternative 1 will only work for Residential non-demand meters.)

Alternative 2: Upgrade TS1 metering system to TS2 at substations and use new TS2 meters for TOU customers

Advanced Metering Costs - Garkane Energy Cooperative

Alternative 1: Use existing TS1 metering system with compatible meters for Residential TOU customers

This alternative will only work for Residential non-demand meters.

Incremental Cost Estimate	Cost ($)	Based on 10% Penetration assumed # meters	Total Cost ($)	Cost per TOU meter ($)
meters (each)	511	54	27,594	511
billing software upgrade	640	54	640	12
Total =		54	28,234	523

Alternative 2: Upgrade TS1 metering system to TS2 at substations and use new TS2 meters for TOU customers

Residential only

Incremental Cost Estimate	assumed # meters	Total Cost ($)	Cost per TOU meter ($)
L&G TS2 upgrade (equip,software,training,certification) with 54 res meters		96,370	
Travel expense for commissioning & training		6,000	
Fredonia substation installation of TS2 & related equipment		37,018	
Ryan substation installation of TS2 & related equipment		33,593	
AC power installation at the two substations		2,000	
Internet service at Fredonia Sub (plus monthly cost of $59)		195	
Internet service at Ryan Sub via satellite dish (plus monthly cost of $39)		2,600	
Router & firewalls		1,200	
Specialized test equipment		3,333	
billing software upgrade (for one new rate)		640	
Total =	54	182,948	3,388
Estimated net installed cost with possible Smart Grid ARRA 50% grant*	54	111,874	2,072

All Non-Lighting Rates

Incremental Cost Estimate	assumed # meters	Total Cost ($)	Cost per TOU meter ($)
L&G TS2 upgrade with 70 meters (54 residential+16 comm)		98,530	
Travel expense for commissioning & training		6,000	
Fredonia substation installation of TS2 & related equipment		37,018	
Ryan substation installation of TS2 & related equipment		33,593	
AC power installation at the two substations		2,000	
Internet service installation at Fredonia Sub (plus $59/mon)		195	
Internet service installation at Ryan Sub via satellite dish (plus $39/mon)		2,600	
Router & firewalls		1,200	
Specialized test equipment		3,333	
billing software upgrade		3,200	
Total =	70	187,668	2,681
Estimated net installed cost with possible Smart Grid ARRA 50% grant*	70	114,234	1,632

Alternative 1 - Cost estimate:	Per Meter ($) * TOU	Non-TOU	Delta
Meter	378	89	289
S&H	76	18	58
Subtotal	454	107	347
Installation	127	20	107
Travel	60	3	57
Subtotal	187	23	164
Total Incremental Meter-related costs	641	130	511

* Stellar Grants has a contract with Landis & Gyr to assist customers in the application for a Smart Grid ARRA grant (American Recovery & Reinvestment Act of 2009) These grants may be available on a matching funds basis to cover up to 50% of the cost. Stellar Grants fee to prepare and apply for the grant on behalf of the cooperative is $20,400.

Source: Garkane provided cost data from vendors
Alternative 1 cost estimate from ACC staff analysis for L&G AXS4e poly-phase meters
(actual cost may differ depending on cost of available meters compatible with TS1 system)

ATTACHMENT 5

Garkane Energy
L. Alt
4-8-09

2009 RATE PROPOSAL 1
Using 12 Months Ending August 31, 2008 Units

General Rate Increase Rate Proposal 1		
For Revenue Increase of:	$ 33,162	2.52%

Arizona Rate Schedule	Title	Rate Elements	12 months End 8-31-08 Units	1-Aug-08 Current Price ($)	Yr End 8-31-08 Projected Revenue ($)	With Opt. TOU Rates* Units	Proposed Price ($)	Proposed Revenue ($)	% Change Revenue
1	Residential	Base Rate	6,433	12.5	80,413	5,790	13.00	75,270	-6.40%
		All Kwh	7,838,266	0.06907	541,389	5,878,700	0.073	429,145	-20.73%
		Calc'd Rate Revenue			621,802			504,415	-18.88%
1TOU	Residential - optional TOU	Base Rate		12.5	-	643	32.00	20,576	
		Kwh on peak		0.06907		-	0.1129	-	
		Kwh off peak		0.06907		1,959,567	0.0584	114,439	
		Calc'd Rate Revenue			-			135,015	
		Calc'd Rate Revenue - Total Residential:			621,802			639,430	2.84%
								-	
4	Irrigation	Base Rate -annual 1ph	191	75	14,325	172	100	17,200	20.07%
		Base Rate -annual 3ph	0	125	-		200	-	
		All Kwh	511065	0.05723	29,248	383,299	0.057	21,848	-25.30%
		Demand all Kw	2379	5.31	12,632	1,784	5.35	9,544	-24.45%
		Calc'd Rate Revenue			56,206			48,592	-13.55%
4TOU	Irrigation- optional TOU	Base Rate -annual 1ph		75	-	19	328	6,232	
		Base Rate -annual 3ph		125	-		428	-	
		All Kwh		0.05723	-	127,766	0.052	6,644	
		Demand On Peak Kw		5.31	-	595	10.00	5,950	
		Calc'd Rate Revenue			-			18,826	
		Calc'd Rate Revenue - Total Irrigation:			56,206			67,418	19.95%
5	General Service 1	Base Rate	1437	12.5	17,963	1,293	15.00	19,395	7.97%
		All Kwh	2794014	0.05845	163,310	2,095,511	0.057	119,444	-26.86%
		Demand all Kw	10674	6.37	67,993	8,006	6.37	50,998	-25.00%
		Calc'd Rate Revenue			249,266			189,837	-23.84%
5TOU	General Service 1 - optional TOU	Base Rate		12.5	-	144	34.00	4,896	
		All Kwh		0.05845	-	698,504	0.052	36,322	
		Demand On Peak Kw		6.37	-	2,669	10.00	26,690	
		Calc'd Rate Revenue			-			67,908	
		Calc'd Rate Revenue - Total 5 Gen Service 1:			249,266			257,746	3.40%
6	General Service 1-Pub Auth	Base Rate	84	12.5	1,050	76	15.00	1,140	8.57%
		All Kwh	356252	0.05845	20,823	267,189	0.057	15,230	-26.86%
		Demand all Kw	1731	6.37	11,026	1,298	6.37	8,268	-25.01%
		Calc'd Rate Revenue			32,899			24,638	-25.11%
6TOU	Gen Svc 1-Pub Auth-optional TOU	Base Rate		12.5	-	8	34.00	272	
		All Kwh		0.05845	-	89,063	0.052	4,631	
		Demand On Peak Kw		6.37	-	433	10.00	4,330	
		Calc'd Rate Revenue			-			9,233	
		Calc'd Rate Revenue - Total 6 Gen Service 1:			32,899			33,871	2.95%
8	General Service 2	Base Rate	60	20	1,200	54	30.00	1,620	35.00%
		All Kwh	4434160	0.06115	271,149	3,325,620	0.059	196,212	-27.64%
		Demand all Kw	12617	6.37	80,370	9,463	6.37	60,279	-25.00%
		Calc'd Rate Revenue			352,719			258,111	-26.82%
8TOU	General Service 2-optional TOU	Base Rate		20	-	6	49.00	294	
		All Kwh		0.06115	-	1,108,540	0.052	57,644	
		Demand On Peak Kw		6.37	-	3,154	10.00	31,540	
		Calc'd Rate Revenue			-			89,478	
		Calc'd Rate Revenue - Total 8 Gen Service 2:			352,719			347,589	-1.45%
7	Street & Yard Lighting	100w	576	8.12	4,677	576	8.12	4,677	0.00%
		Calc'd AZ Rate Revenue			1,317,569			1,350,731	2.52%

***NOTE:**	All TOU rates are based on assumed participation rate of:	10%
	and assumed load shift to off peak of :	25%
	Also assumed all non-lighting rates have TOU option	
	and use of 50% ARRA grant for costs	

ATTACHMENT 6

Garkane Fixed Charge Rate Calculation:

Total Utility Plant (including contributions in aid of contruction)	90,995,834	
Interest	1,688,618	1.86%
Oper & Maint	7,254,625	7.97%
Taxes - property	274,534	0.30%
Depreciation		3.90%
		14.03%

Average Meter O&M expense

Total Meter Plant in service	2,206,149	
Oper & Maint Exp - Meters	325,207	14.74%

Source: 2008 Garkane CFC Form 7 & Annual report to Utah PSC

Estimate of Residential TOU Conversion Benefits
Garkane Energy

* Assumed load shift =	25%
** Assumed penetration	10%

2008	(1) Total kwh System	(2) Total kwh sold in AZ	(3) Res kwh sold in AZ	(4)=(3)/(2) Res % of total AZ	(5) Total CP billed kw	(6)=(2)/(1) AZ % of Tot Sys	(7)=(4)x(5)x(6) AZ res share of UT cp kw	(8) Avg No AZ Res custs	(9)=(7)/(8) Avg cp kw per cust	(10) Load shift * kw benefit per cust	(11) No Custs on TOU **	(12) Incremental*** $ per kw	(13)= (10)x(11)x(12) Est Value to Garkane	(14)= (10)x(12) Value per cust
Jan	21,058,477	1,545,817	946,171	61.2%	44,685	7%	2,008	543	3.70	0.92	54	8.518	$425	$8
Feb	20,832,157	1,540,089	902,932	58.6%	40,628	7%	1,761	543	3.24	0.81	54	8.518	$373	$7
Mar	16,205,732	1,197,250	684,935	57.2%	34,499	7%	1,458	543	2.69	0.67	54	8.518	$309	$6
Apr	15,145,324	1,302,199	618,822	47.5%	31,371	9%	1,282	541	2.37	0.59	54	8.518	$272	$5
May	15,055,336	1,341,064	493,234	36.8%	25,451	9%	834	541	1.54	0.39	54	8.518	$177	$3
Jun	14,187,718	1,216,928	489,737	40.2%	29,581	9%	1,021	539	1.89	0.47	54	8.518	$218	$4
Jul	15,468,762	1,539,594	665,255	43.2%	31,907	10%	1,372	542	2.53	0.63	54	8.518	$291	$5
Aug	16,579,185	1,520,570	733,455	48.2%	29,893	9%	1,322	539	2.45	0.61	54	8.518	$282	$5
Sep	14,855,545	1,431,596	653,782	45.7%	25,060	10%	1,103	542	2.03	0.51	54	8.518	$234	$4
Oct	13,833,081	1,344,581	548,583	40.8%	23,421	10%	929	539	1.72	0.43	54	8.518	$198	$4
Nov	14,081,796	1,432,478	512,562	35.8%	30,122	10%	1,096	538	2.04	0.51	54	8.518	$234	$4
Dec	16,752,705	1,689,867	644,732	38.2%	37,868	10%	1,457	539	2.70	0.68	54	8.518	$311	$6
Sum	194,055,818	17,102,033	7,894,200	46.2%	384,486		15,644						$3,325	$62
Average				46.1%				541	2.41	0.60	54			

*** Used 2008 DGT incremental CP billing $/kw + potential $2/kw increase
Source: 2008 Garkane billing data & DGT billing data

ATTACHMENT 8

Estimate of All Non-Lighting Rates TOU Conversion Benefits
Garkane Energy

* Assumed load shift =	25%
** Assumed penetration =	10%

2008	(1) Total kwh System	(2) Total kwh sold in AZ	(3) non-lighting kwh in AZ	(4)=(3)/(2) non-ltg % of total AZ	(5) Total CP billed kw	(6)=(2)/(1) AZ % of Tot Sys	(7)=(4)x(5)x(6) AZ NL share of AZ cp kw	(8) Avg No AZ non-ltg custs	(9)=(7)/(8) Avg cp kw per cust	(10) Load shift * kw benefit per cust	(11) No Custs on TOU **	(12) Incremental*** $ per kw	(13)= (10)x(11)x(12) Est Value to Garkane	(14)= (10)x(12) Value per cust
Jan	21,058,477	1,545,817	1,544,577	99.9%	44,685	7%	3,278	686	4.78	1.19	69	8.518	$702	$10
Feb	20,832,157	1,540,089	1,538,849	99.9%	40,628	7%	3,001	684	4.39	1.10	68	8.518	$635	$9
Mar	16,205,732	1,197,250	1,196,010	99.9%	34,499	7%	2,546	685	3.72	0.93	69	8.518	$546	$8
Apr	15,145,324	1,302,199	1,300,959	99.9%	31,371	9%	2,695	687	3.92	0.98	69	8.518	$576	$8
May	15,055,336	1,341,064	1,339,824	99.9%	25,451	9%	2,265	693	3.27	0.82	69	8.518	$480	$7
Jun	14,187,718	1,216,928	1,215,688	99.9%	29,581	9%	2,535	691	3.67	0.92	69	8.518	$539	$8
Jul	15,468,762	1,539,594	1,538,354	99.9%	31,907	10%	3,173	696	4.56	1.14	70	8.518	$680	$10
Aug	16,579,185	1,520,570	1,519,330	99.9%	29,893	9%	2,739	692	3.96	0.99	69	8.518	$582	$8
Sep	14,855,545	1,431,596	1,430,356	99.9%	25,060	10%	2,413	696	3.47	0.87	70	8.518	$517	$7
Oct	13,833,081	1,344,581	1,343,341	99.9%	23,421	10%	2,274	693	3.28	0.82	69	8.518	$482	$7
Nov	14,081,796	1,432,478	1,431,238	99.9%	30,122	10%	3,062	691	4.43	1.11	69	8.518	$651	$9
Dec	16,752,705	1,689,867	1,688,627	99.9%	37,868	10%	3,817	687	5.56	1.39	69	8.518	$816	$12
Sum	194,055,818	17,102,033	17,087,153	99.9%	384,486		33,797						$7,207	$104
Average				99.9%				690	4.08	1.02	69			

*** Used 2008 DGT incremental CP billing $/kw + potential $2/kw surcharge for growth
Source: 2008 Garkane billing data & DGT billing data

ATTACHMENT 9

AMI Cost Summary Garkane
L.Alt
4-6-09

GARKANE ENERGY COOPERATIVE
(Docket No. E-01891A-08-0061)

Cost Analysis Summary - Garkane Energy Cooperative

Based on assumed peak load shift of 25% and 10% of customers participating

	(a) Total Company Incremental Cost ($)	(b) Annualized Cost ($)	(c) Annual Benefit ($)	(d) =(c)/(b) Benefit/Cost Ratio	(e) Monthly Cost ($) per Cust	(f) Monthly Benefit ($) per Cust	(g) For B/C = 1 Additional Savings/year Needed ($)	(h) Year 1 Rev Req per Cust Impact ($)	(i) w/meter o&m Monthly Rev Req ($) per Cust	(j) w/avg o&m Monthly Rev Req ($) per Cust	(k) Pres Value Rev Req per Cust ($)
Alternative 1											
Residential only (54 custs)	28,234	3,961	3,325	0.84	6.11	5.13	636				
Alternative 2											
Residential only (54 custs)	182,948	25,667	3,325	0.13	39.61	5.13	22,342	870	72.49	53.38	13,180
Residential only (54 custs) with 50% ARRA grant	111,874	15,696	3,325	0.21	24.22	5.13	12,371	508	42.33	30.65	7,626
All Non-Lighting (70 custs)	187,668	26,330	7,207	0.27	31.34	8.70	19,123	633	52.73	37.61	9,422
All Non-Lighting (70 custs) with 50% ARRA grant	114,234	16,027	7,207	0.45	19.08	8.70	8,820	344	28.69	19.49	4,995

Alternative 1: Use existing TS1 metering system with compatible meters for TOU customers
(Alternative 1 will only work for Residential non-demand meters.)

Alternative 2: Upgrade TS1 metering system to TS2 at substations and use new TS2 meters for TOU customers

NOTES:
(a) Total cost of metering & related investment
(b) Annualized using Fixed Charge Rate of 14.03%
(c) Calculated from peak demand reduction savings
(e) =(b)/12/number of customers
(f) =(c)/12/number of customers (cost for 70 custs, avg benefits for 69 avg custs)
(g) additional savings/yr beyond peak demand reduction needed for benefit/cost ratio =1 (=b-c)
(h) Rev Req=O&M+taxes+deprec+(TIER x interest exp)-avoided capacity costs
(i) using meter O&M exp = 14.74% of meter plant
(j) using avg O&M exp of 7.97% of total plant
(k) present value of rev req impact over 25 years

AMI Cost Analysis-G
L.Alt
4-4-09

Garkane Revenue Requirement Impact
of Proposed Advanced Metering Infrastructure (upgrade TS1 to TS2)
(average incremental impact per TOU customer)
(Incremental Revenue Requirement = incremental expenses + (required TIER x incremental Interest expense))

For impact of TOU rates for all non-lighting--enter NL, for residential only--enter RES : NL
To determine impact of a 50% ARRA Grant, enter G: G

Year	(a) avg/cust kw savings	(b) avoided capacity cost (5) ($/kw/yr)	(c)=(a)x(b) tot avoided cost($) (6)	(d) O&M	(e) taxes	(f) deprec	(g)=(d)+(e)+(f)-(c) net exp ($)	(h) interest per $100	(i) TIER req'mt rev req chg	(j)=(g)+(i) net rev req impact/cust	(j) discount factor	(k) discounted rev req impact
1	1.02	102.22	104.33	240.56	4.92	63.64	204.79	$5.70	139.53	344.32	1.00	344.32
2	1.02	102.22	104.33	247.78	5.07	63.64	212.16	$5.59	136.88	349.04	0.95	330.21
3	1.02	105.28	107.46	255.21	5.22	63.64	216.61	$5.48	134.07	350.69	0.90	313.88
4	1.02	108.44	110.69	262.87	5.38	63.64	221.20	$5.36	131.11	352.31	0.85	298.33
5	1.02	111.69	114.01	270.75	5.54	63.64	225.93	$5.23	127.98	353.91	0.80	283.52
6	1.02	115.05	117.43	278.87	5.71	63.64	230.80	$5.09	124.67	355.46	0.76	269.41
7	1.02	118.50	120.95	287.24	5.88	63.64	235.81	$4.95	121.17	356.98	0.72	255.97
8	1.02	122.05	124.58	295.86	6.06	63.64	240.98	$4.80	117.47	358.44	0.68	243.16
9	1.02	125.71	128.32	304.73	6.24	63.64	246.30	$4.64	113.56	359.85	0.64	230.95
10	1.02	129.48	132.17	313.88	6.42	63.64	251.78	$4.47	109.42	361.20	0.61	219.32
11	1.02	133.37	136.13	323.29	6.62	63.64	257.42	$4.29	105.05	362.48	0.57	208.22
12	1.02	137.37	140.22	332.99	6.82	63.64	263.24	$4.10	100.44	363.67	0.54	197.64
13	1.02	141.49	144.42	342.98	7.02	63.64	269.22	$3.90	95.56	364.78	0.51	187.56
14	1.02	145.74	148.75	353.27	7.23	63.64	275.39	$3.69	90.40	365.79	0.49	177.93
15	1.02	150.11	153.22	363.87	7.45	63.64	281.74	$3.47	84.94	366.69	0.46	168.75
16	1.02	154.61	157.81	374.78	7.67	63.64	288.29	$3.23	79.18	367.47	0.44	159.99
17	1.02	159.25	162.55	386.03	7.90	63.64	295.03	$2.99	73.09	368.11	0.41	151.63
18	1.02	164.03	167.42	397.61	8.14	63.64	301.97	$2.72	66.65	368.61	0.39	143.65
19	1.02	168.95	172.45	409.54	8.38	63.64	309.12	$2.44	59.84	368.96	0.37	136.03
20	1.02	174.02	177.62	421.82	8.63	63.64	316.48	$2.15	52.65	369.13	0.35	128.75
21	1.02	179.24	182.95	434.48	8.89	63.64	324.07	$1.84	45.04	369.11	0.33	121.80
22	1.02	184.61	188.44	447.51	9.16	63.64	331.88	$1.51	37.00	368.88	0.31	115.16
23	1.02	190.15	194.09	460.94	9.43	63.64	339.92	$1.16	28.51	368.43	0.30	108.82
24	1.02	195.86	199.91	474.77	9.72	63.64	348.21	$0.80	19.53	367.74	0.28	102.76
25	1.02	201.73	205.91	489.01	10.01	63.64	356.75	$0.41	10.03	366.78	0.26	96.96

Present value of revenue requirement impact per TOU customer = $ 4,994.76
(this is the PV amount of other company &/or societal benefits
per TOU customer needed to offset the incremental cost of AMI)

Required monthly customer charge increase for TOU customers = $ 28.69

INPUT DATA

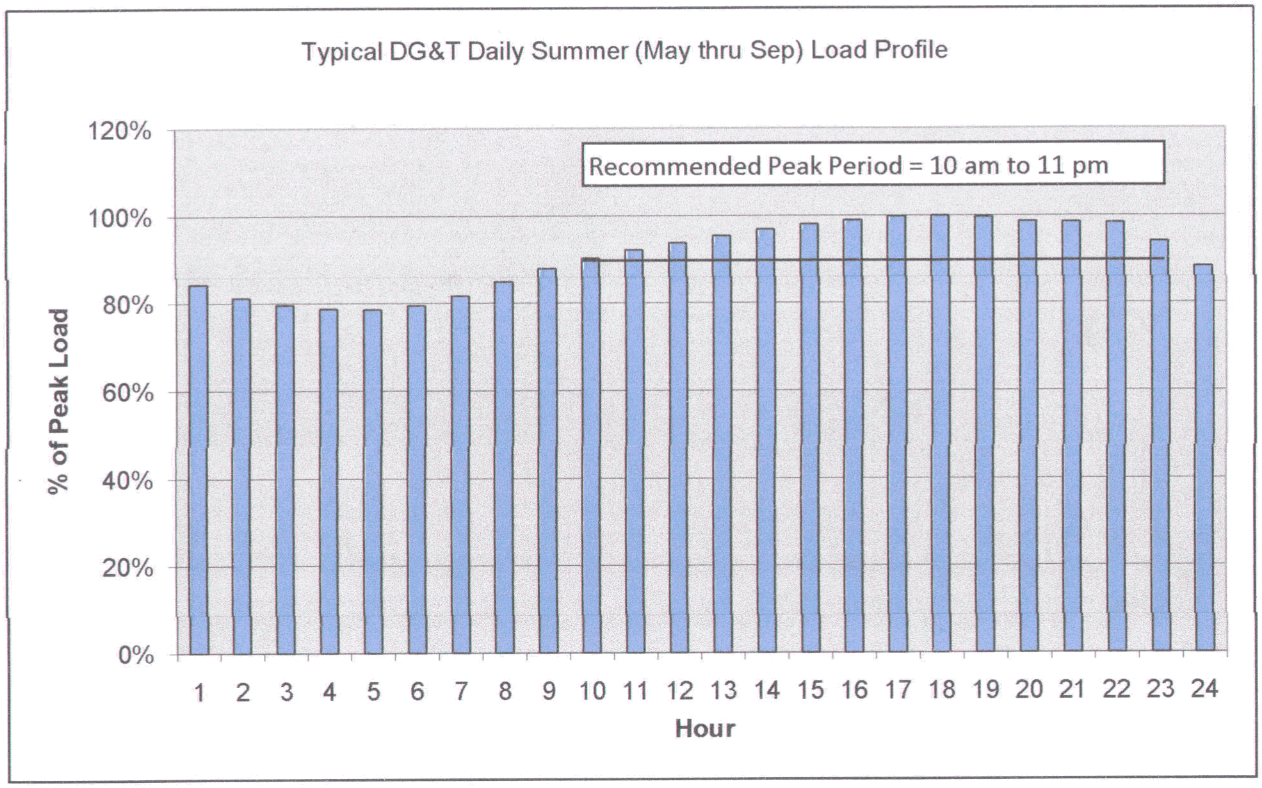
avg CP kw/month/cust saving	1.02	NL	
inflation (assumed) =	3.0%		
LT debt - current interest exp (1)	5.7%		
avoided capacity cost (2) ($/kw/mon)	$ 8.518		
TIER requirement (3)	1.5		
avg meter O&M expense (4)	14.74%		
avg property tax expense (4)	0.30%		
depreciation exp - distribution plant (4)	3.90%		
avg adv metering cost/cust	$ 1,632	NL	G

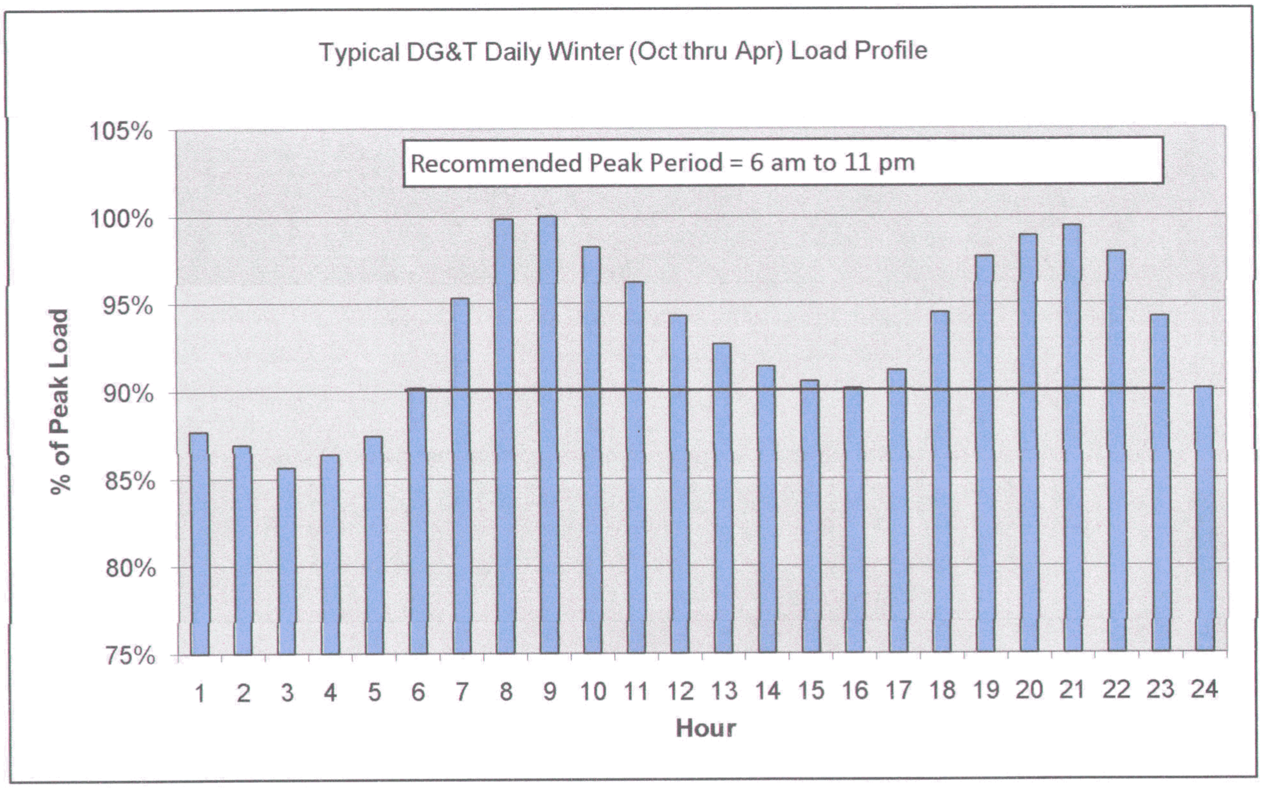
SOURCE
(1) Garkane estimate
(2) Incremental capacity cost - December 2008 Deseret Power bill + potential $2/kw surcharge for growth
(3) Garkane
(4) Garkane 2008 Annual Report to Utah PSC
(5) Avoided capacity cost (annual) - inflated
(6) assumes incentive for load shift = cost savings

ATTACHMENT 11

Typical DGT Daily Load Profile for Summer and Winter

HE	Sum	Win
1	84%	88%
2	81%	87%
3	80%	86%
4	79%	86%
5	79%	87%
6	79%	90%
7	82%	95%
8	85%	100%
9	88%	100%
10	90%	98%
11	92%	96%
12	94%	94%
13	95%	93%
14	97%	91%
15	98%	91%
16	99%	90%
17	100%	91%
18	100%	94%
19	100%	98%
20	99%	99%
21	98%	99%
22	98%	98%
23	94%	94%
24	88%	90%





Data provided by DGT
L.Alt
3-30-09

ATTACHMENT 12

System Peak Times

Deseret System Peaks

	2004	Hour	2005	Hour	2006	Hour	2007	Hour	2008	Hour	5 Year Range of Peak Days	5 Year Range of Peak Hours
Jan	Monday, January 05, 2004	8:00 AM	Thursday, January 13, 2005	8:00 AM	Monday, January 23, 2006	8:00 AM	Tuesday, January 16, 2007	8:00 AM	Thursday, January 17, 2008	8:00 AM	M,TU,TH	8A
Feb	Thursday, February 12, 2004	8:00 AM	Wednesday, February 09, 2005	8:00 AM	Monday, February 06, 2006	8:00 AM	Friday, February 02, 2007	8:00 AM	Tuesday, February 05, 2008	8:00 AM	M,TU,W,TH,F	8A
Mar	Monday, March 01, 2004	8:00 AM	Tuesday, March 15, 2005	8:00 AM	Monday, March 13, 2006	8:00 AM	Friday, March 02, 2007	8:00 AM	Thursday, March 06, 2008	8:00 AM	M,TU,TH,F	8A
Apr	Tuesday, April 27, 2004	9:00 PM	Monday, April 11, 2005	8:00 AM	Tuesday, April 18, 2006	8:00 AM	Monday, April 30, 2007	10:00 PM	Tuesday, April 01, 2008	9:00 AM	M,TU	8A-10P
May	Tuesday, May 04, 2004	10:00 PM	Tuesday, May 24, 2005	6:00 PM	Thursday, May 18, 2006	5:00 PM	Thursday, May 31, 2007	5:00 PM	Monday, May 19, 2008	6:00 PM	M,TU,TH	5P-10P
Jun	Monday, June 14, 2004	6:00 PM	Thursday, June 30, 2005	7:00 PM	Monday, June 26, 2006	6:00 PM	Thursday, June 28, 2007	7:00 PM	Monday, June 30, 2008	4:00 PM	M,TH	4P-10P
Jul	Monday, July 12, 2004	7:00 PM	Tuesday, July 19, 2005	6:00 PM	Monday, July 17, 2006	4:00 PM	Monday, July 02, 2007	6:00 PM	Thursday, July 10, 2008	6:00 PM	M,TU,TH	4P-7P
Aug	Wednesday, August 11, 2004	4:00 PM	Monday, August 29, 2005	6:00 PM	Wednesday, August 23, 2006	4:00 PM	Monday, August 13, 2007	5:00 PM	Thursday, August 14, 2008	5:00 PM	M,W,TH	4P-6P
Sep	Wednesday, September 01, 2004	9:00 PM	Thursday, September 01, 2005	5:00 PM	Saturday, September 02, 2006	6:00 PM	Tuesday, September 04, 2007	5:00 PM	Sunday, September 07, 2008	6:00 PM	TU,W,TH,SA,SU	5P-9P
Oct	Friday, October 29, 2004	9:00 AM	Monday, October 03, 2005	9:00 PM	Tuesday, October 03, 2006	9:00 PM	Monday, October 22, 2007	8:00 AM	Wednesday, October 01, 2008	5:00 PM	M,TU,W,F	8A-9P
Nov	Monday, November 29, 2004	8:00 PM	Monday, November 28, 2005	8:00 AM	Thursday, November 30, 2006	8:00 AM	Thursday, November 29, 2007	8:00 AM	Monday, November 24, 2008	8:00 AM	M,TH	8A-8P
Dec	Wednesday, December 01, 2004	8:00 AM	Thursday, December 15, 2005	8:00 AM	Wednesday, December 20, 2006	8:00 AM	Thursday, December 27, 2007	8:00 PM	Monday, December 15, 2008	7:00 PM	M,W,TH	8A-8P

Dixie-Escalante System Peaks

	2004	Hour	2005	Hour	2006	Hour	2007	Hour	2008	Hour	5 Year Range of Peak Days	5 Year Range of Peak Hours
Jan	Tuesday, January 06, 2004	8:00 AM	Thursday, January 13, 2005	8:00 AM	Tuesday, January 17, 2006	8:00 AM	Tuesday, January 16, 2007	8:00 AM	Thursday, January 17, 2008	8:00 AM	TU,TH	8A
Feb	Friday, February 13, 2004	8:00 AM	Wednesday, February 09, 2005	8:00 AM	Tuesday, February 21, 2006	8:00 AM	Friday, February 02, 2007	8:00 AM	Wednesday, February 06, 2008	8:00 AM	TU,W,F	8A
Mar	Monday, March 01, 2004	8:00 AM	Tuesday, March 15, 2005	8:00 AM	Tuesday, March 14, 2006	8:00 AM	Thursday, March 01, 2007	8:00 AM	Thursday, March 06, 2008	8:00 AM	M,TU,TH	8A
Apr	Tuesday, April 27, 2004	4:00 PM	Monday, April 11, 2005	8:00 AM	Sunday, April 30, 2006	6:00 PM	Sunday, April 29, 2007	7:00 PM	Tuesday, April 29, 2008	4:00 PM	SU,M,TU	8A-7P
May	Wednesday, May 05, 2004	7:00 PM	Friday, May 27, 2005	4:00 PM	Friday, May 19, 2006	8:00 PM	Thursday, May 17, 2007	6:00 PM	Monday, May 19, 2008	7:00 PM	M,W,TH,F	4P-8P
Jun	Thursday, June 24, 2004	5:00 PM	Monday, June 20, 2005	7:00 PM	Thursday, June 29, 2006	5:00 PM	Friday, June 22, 2007	5:00 PM	Monday, June 30, 2008	5:00 PM	M,TH,F	5P-7P
Jul	Thursday, July 22, 2004	5:00 PM	Tuesday, July 19, 2005	6:00 PM	Tuesday, July 25, 2006	5:00 PM	Thursday, July 05, 2007	4:00 PM	Wednesday, July 09, 2008	6:00 PM	TU,W,TH	4P-6P
Aug	Wednesday, August 11, 2004	4:00 PM	Monday, August 29, 2005	6:00 PM	Tuesday, August 22, 2006	7:00 PM	Wednesday, August 15, 2007	5:00 PM	Thursday, August 14, 2008	5:00 PM	M,TU,W,TH	4P-7P
Sep	Wednesday, September 01, 2004	4:00 PM	Thursday, September 01, 2005	6:00 PM	Tuesday, September 05, 2006	5:00 PM	Tuesday, September 04, 2007	5:00 PM	Sunday, September 07, 2008	6:00 PM	SU,TU,W,TH	4P-6P
Oct	Wednesday, October 06, 2004	6:00 PM	Monday, October 03, 2005	9:00 PM	Tuesday, October 03, 2006	11:00 PM	Monday, October 22, 2007	8:00 AM	Wednesday, October 01, 2008	5:00 PM	M,TU,W	8A-9P
Nov	Tuesday, November 30, 2004	8:00 AM	Monday, November 28, 2005	8:00 AM	Thursday, November 30, 2006	8:00 AM	Thursday, November 29, 2007	8:00 AM	Monday, November 24, 2008	8:00 AM	M,TU,TH	8A
Dec	Wednesday, December 01, 2004	8:00 AM	Friday, December 16, 2005	8:00 AM	Thursday, December 21, 2006	8:00 AM	Wednesday, December 12, 2007	8:00 AM	Monday, December 15, 2008	7:00 PM	M,W,TH,F	8A-7P

Garkane System Peaks

	2004	Hour	2005	Hour	2006	Hour	2007	Hour	2008	Hour	5 Year Range of Peak Days	5 Year Range of Peak Hours
Jan	Monday, January 05, 2004	8:00 AM	Friday, January 07, 2005	8:00 AM	Monday, January 23, 2006	8:00 AM	Tuesday, January 16, 2007	8:00 AM	Thursday, January 17, 2008	8:00 AM	M,TU,TH,F	8A
Feb	Thursday, February 12, 2004	8:00 AM	Wednesday, February 09, 2005	8:00 AM	Tuesday, February 21, 2006	8:00 AM	Friday, February 02, 2007	8:00 AM	Thursday, February 07, 2008	8:00 AM	TU,W,TH,F	8A
Mar	Monday, March 01, 2004	8:00 AM	Tuesday, March 15, 2005	8:00 AM	Monday, March 13, 2006	8:00 AM	Thursday, March 01, 2007	8:00 AM	Wednesday, March 05, 2008	8:00 AM	M,TU,W,TH	8A
Apr	Friday, April 30, 2004	8:00 AM	Friday, April 01, 2005	8:00 AM	Tuesday, April 18, 2006	8:00 AM	Thursday, April 19, 2007	8:00 AM	Thursday, April 10, 2008	8:00 AM	TU,TH,F	8A
May	Saturday, May 29, 2004	10:00 PM	Saturday, May 28, 2005	10:00 PM	Saturday, May 27, 2006	2:00 PM	Saturday, May 26, 2007	10:00 PM	Friday, May 23, 2008	10:00 PM	F,SA	2P-10P
Jun	Monday, June 14, 2004	7:00 PM	Thursday, June 30, 2005	7:00 PM	Friday, June 23, 2006	6:00 PM	Friday, June 22, 2007	7:00 PM	Saturday, June 28, 2008	7:00 PM	M,TH,F,SA	6P-7P
Jul	Friday, July 23, 2004	10:00 PM	Thursday, July 21, 2005	5:00 PM	Thursday, July 27, 2006	1:00 PM	Wednesday, July 04, 2007	6:00 PM	Thursday, July 10, 2008	7:00 PM	W,TH,F	1P-10P
Aug	Wednesday, August 11, 2004	7:00 PM	Monday, August 29, 2005	7:00 PM	Thursday, August 24, 2006	3:00 PM	Monday, August 13, 2007	2:00 PM	Friday, August 01, 2008	6:00 PM	M,W,TH,F	2P-7P
Sep	Saturday, September 04, 2004	9:00 PM	Saturday, September 03, 2005	9:00 PM	Saturday, September 02, 2006	9:00 PM	Sunday, September 02, 2007	6:00 PM	Monday, September 01, 2008	11:00 AM	SU,M,SA	11A-9P
Oct	Thursday, October 28, 2004	8:00 PM	Thursday, October 06, 2005	8:00 AM	Thursday, October 26, 2006	8:00 AM	Monday, October 22, 2007	8:00 AM	Monday, October 13, 2008	8:00 AM	M,TH	8A-8P
Nov	Tuesday, November 30, 2004	8:00 AM	Monday, November 28, 2005	8:00 AM	Thursday, November 30, 2006	8:00 AM	Thursday, November 29, 2007	8:00 AM	Thursday, November 06, 2008	8:00 AM	M,TU,TH	8A
Dec	Wednesday, December 01, 2004	8:00 AM	Thursday, December 08, 2005	8:00 AM	Monday, December 18, 2006	8:00 AM	Friday, December 28, 2007	9:00 AM	Saturday, December 27, 2008	9:00 AM	M,W,TH,F,SA	8A-9A

Source: Deseret Monthly Billing data

	DGT	Dixie	Garkane	Recommend
Peak Hours				
Summer (May thru Sept)	4p-10p	4p-8p	1p-10p	10a-11p
Winter (Oct thru April)	8a-10p	8a-9p	8a-8p	6a-11p
Peak Days of Week				
Summer (May thru Sept)	all except Friday	all except Saturday	all except Tuesday	all days of the week
Winter (Oct thru April)	all except Saturday & Sunday	all except Saturday	all except Sunday	all days of the week

L.Alt
3-30-09

ATTACHMENT 13

Possible Advanced Metering Infrastructure Benefits

The following list of benefits is not intended to be complete and has not been quantified. Some of these benefits are particularly difficult to quantify. Time-of-use rates allow for shifting of loads to off peak periods. If usage is shifted, but not reduced, power plant emissions are also shifted.

1. Company Benefits
    a. Allows for automated net metering billing
    b. Automates outage detection, reducing outage durations (& lost revenue)
    c. Information on momentary outages
    d. Can help identifies theft of service
    e. Automates remote meter connect/disconnect, reduces trips to meter
    f. Can obtain final meter readings without trip to meter
    g. Better customer service – better customer usage information
    h. Better demand info for system planning & operation & cost studies
    i. Reduced costs from eliminating manual meter reading & billing
    j. Peak demand reductions through use of time-of-use rate options
2. Customer Benefits
    a. Allows for more time-of-use rate options through which the customer can achieve cost savings
    b. Better customer usage information
    c. More privacy thru elimination of manual meter reads
    d. More accurate bills thru elimination of manual meter reads
    e. Reduced outage durations & related costs
    f. Reduced company costs results in reduced prices to customers
3. Societal Benefits
    a. AMI does not produce, but enables societal benefits thru other initiatives
    b. Demand response programs can result in peak demand reductions
    c. Time-of-use programs can result in peak demand reductions
    d. Reduced outage durations
    e. Reduction of externalities
    f. Fewer company vehicles on the road & miles traveled
    g. Can enable programs that reduce carbon emissions

L.Alt
4-7-09

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Landis+Gyr
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Date: March 5, 2009
Quote Number: 003234-20090305

Company Name	Garkane Energy
Contact	Craig Twitchell / Mike Avant
Address	PO Box 4765
City, State, Zip	Hatch, UT 84735
Phone Number	435-735-4288
Email	ctwitchell@garkaneenergy.com / mavant@garkaneenergy.com

[illegible]
[illegible] Deployment at 2 [illegible] - Summary

Description	Unit Price	Qty	Ext. Price
Software			
Subtotal			**$ 5,000.00**
Substation Hardware			
Subtotal			**$ 62,160.00**
Meter Modules - Residential			
Subtotal			**$ 13,536.00**
Meter Modules - Commercial			
Subtotal			**$ -**
Training and Implementation Services			
Subtotal			**$ 32,000.00**
Hunt SubTotal Extended Price			**$ 112,696.00**
Legacy Technologies Upgrade Discount	$ (7,569.60)	1	$ (7,569.60)
Hunt Total Extended Price			**$ 105,126.40**

Account Executive:	Mark Thayer at 218-562-3828
Sales Coordinator:	Junell Wendt at 800-926-6254
Quote Coordinator:	Lisa Hanson at 218-562-5175
Rep Firm:	Hamilton Associates

CONFIDENTIAL

Landis+Gyr
manage energy better

Date: March 5, 2009
Quote Number: 003234-20090305

Company Name	**Garkane Energy**
Contact	**Craig Twitchell / Mike Avant**
Address	**PO Box 4765**
City, State, Zip	**Hatch, UT 84735**
Phone Number	**435-735-4288**
Email	ctwitchell@garkaneenergy.com / mavant@garkaneenergy.com

[redacted]

Description	Part Number	Unit Price	Qty	Ext. Price
Hardware				
*Substation Processing Unit (SPU3000), includes (1) blade with fiber optic output	FASY-0632-0006	$ 14,000.00	2	$ 28,000.00
*Blade Assy, w/o Fiber Optic Output	FASY-0632-0003	$ 3,000.00	4	$ 12,000.00
**Blade Assy, TS1 Advanced DSP	FASY-0632-0005	$ 3,000.00	2	$ 6,000.00
*Blade Assy, Blank	FASY-0632-0004	$ 40.00	4	$ 160.00
*Transformer Coupler Unit, 1X (TCU - 100uH/50uH) Less than 12 MVA	FASY-0532-0003/0004	$ 8,000.00	2	$ 16,000.00
Itron CENTRON® Endpoint (Solid State)	FASY-0539-0003/0004	$ 73.00		$ -
L+G FOCUS® AL Endpoint (Solid State) - can retrofit in field	FASY-0624-0003/0004	$ 70.50		$ -
***L+G FOCUS® AL Endpoint (Solid State) - Integrated	FASY-0694-0001/0002	$ 70.50	192	$ 13,536.00
L+G S4 Underglass Polyphase Endpoint	FASY-0636-0002	$ 150.00		$ -
****TS2 L+G FOCUS® AX, AX-SD Module, Without Zigbee	FASY-0763-0001/0002	$ 85.00		$ -
****TS2 L+G FOCUS® AX, AX-SD Module, With Zigbee	FASY-0764-0001/0002	$ 120.00		$ -
Remote Service Switch (RSS) - Adapter, Single Phase 200 ampere-max	FASY-0528-0001	$ 250.00		$ -
Load Control Switch - 2 relays with validation	FASY-0530-0001	$ 150.00		$ -
User Manual	PUBS-0575-0102	$ -	1	$ -
Subtotal				**$ 75,696.00**
Training and Implementation Services				
TS2 Project Management Services (See Terms/Conditions)	SERV-00035	$ 20,000.00	1	$ 20,000.00
*****Substation Optimization and Commissioning by Hunt Personnel (Per Sub) OPTIONAL (see Sub Commissioning Certification tab for optional choices)	SERV-00024	$ 5,000.00	1	$ 5,000.00
Orientation and First Substation Commissioning with Hunt Field Service Rep	SERV-00034	$ 5,000.00	1	$ 5,000.00
On-site Training with Hunt Training Personnel for 3 days - OPTIONAL	TRAIN-ONSITE	$ 6,000.00		$ -
Training Credits (Number Based on WebEx Classes or Classroom) REQUIRED	TRAIN-00039	$ 31.25	64	$ 2,000.00
Garkane Energy has 32 Training Credits available under the Support Agreement to use against the above line item.				
Subtotal				**$ 32,000.00**
Software				
******TS2 Command Center Software (based on 6,000 endpoints)	FASY-0507-0007	$ 21,600.00	1	$ 21,600.00
Discount	FASY-0507-0007	$ (16,600.00)	1	$ (16,600.00)
Command Center License Fee (per endpoint fee after initial 6,000 endpoint qty)	LICN-00020	$ 0.60		$ -
Remote Service Switch Functionality within Command Center	LICN-00013	$ 3,000.00		$ -
Load Control Switch Functionality within Command Center	LICN-00016	$ 3,000.00		$ -
*******Command Center MDM Add-On OPTIONAL	SFTW-00077	$ 0.60		$ -
Subtotal				**$ 5,000.00**
Hunt Sub-Total Extended Price				**$ 112,696.00**
******Legacy Technology Upgrade Discount	10% Discount	$ (7,569.60)	1	$ (7,569.60)
HUNT TOTAL EXTENDED PRICE				**$ 105,126.40**
Third party hardware you need to purchase:				
Server with SQL License, No Charge with CC-MSP				
Barfield Outdoor Enclosure				
External Feeder CTs				
Transformers-Injection (KVA sizing to be determined)				
Handheld Programmer with Pocket PC2003 (Recommend Symbol Handheld MC9000 Series) - contact Don Stevens of emkat at 763-744-1204, www.emkat.com.				
Fiber Optic Cable (For TCU)				
Fiber Optic Link (For Electric Isolation)				
Communication from Server to Substation				

CISCO® Router				
DCB Modems/Routers: Recommended site is: www.dcbnet.com				

See next tab for Assumptions

Account Executive: Mark Thayer at 218-562-3828
Sales Coordinator: Junell Wendt at 800-926-6254
Quote Coordinator: Lisa Hanson at 218-562-5175
Rep Firm: Hamilton Associates
Substation Communications Specialist: Brad Caraway at 816-679-1435 or brad.caraway@landisgyr.com

***Substation Equipment Assumptions:**
Substation equipment pricing may vary depending on actual substation configurations, feeds and requirements.
SPU3000 Supports Streaming data, additional cards may be needed to improve signal to noise ratio.
**Release of the functional support in Command Center Version 4.0 for the TS1 Blade is scheduled for Q2 2009.

Endpoint Assumptions:
Customer will be responsible to place PO with Rep for meters.
***FOCUS Integrated endpoint must be factory installed and can not be retrofitted in the field. When placing the meter order with Landis+Gyr Energy Measurement Products, use catalog number EA1100"UA"-0000.
****TS2 FOCUS AX, AX-SD Module -

1. Release of module without Zigbee with functional support in Command Center 4.1 is scheduled for approximately August 2009.
2. Release of module with Zigbee with functional support in Command Center 4.1 or may be delayed to 4.2 (scheduled for approximately November 2009) depending on development timelines.
3. TS2 FOCUS AX/AX-SD module is a separate communication module.
4. Module must be ordered either with or without Zigbee – Zigbee can NOT be added to a FASY-0763-0001/0002 module at a later date.
5. We support the following meter forms: 1S, 2S, 3S, 4S, 12S, 25S.
6. Design driven changes may impact pricing.
7. TS2 FOCUS AX/AX-SD module is not capable of controlling the meter display.
8. TS2 FOCUS AX-SD module supports Open, Arm, Close and Service Limiting features of AX-SD meter.
9. TS2 FOCUS AX-SD module sends confirmation of disconnect in following day's packet.
10. TS2 FOCUS AX/AX-SD module firmware does not include DR8 or Enhanced Demand Reset.
11. Zigbee support is limited in this release to Messaging. Pricing and Demand Response clusters are not currently scheduled.

Other Assumptions:
*****If Customer chooses to have Hunt commission its substations, the cost for the first substation commissioning is $5,000, and $3,000 for each additional substation if commissioned in the same week. Hunt can commit to commissioning up to 3 substations in the same week with advance notice so travel arrangements can be made.
******The Legacy Technology Upgrade Discount does not apply to the Load Control Switch, Remote Service Switch, or Focus AX-SD Endpoints
*******Please note that an additional fee of $0.05 per deployed endpoint will be purchased with submission of PO with the Annual Software Agreement for MDM Add-ON - which will provide MDM upgrades.

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TS2 Substation Commissioning Certification Requirements - CONFIDENTIAL

The following steps are required by Hunt Technologies for utility personnel to be certified to commission their own substations. This is an individual certification, not an organizational certification.

Step 1:
Observe Commissioning and Orientation
A Hunt FSR (Field Service Representative) will come on site to commission the first substation with utility personnel observing the commissioning. The Hunt FSR will also provide system orientation.

The cost for this is $5,000.00, which includes the commissioning and orientation.

Step 2:
Classroom Training
TS2 Substation Installation Certification Training: This three-day course in Pequot Lakes covers the best practices for installation of substation components, hands-on training of test equipment used during the process and Command Center set-up items associated with the installation process.

Who Should Attend: This session should be attended by personnel that will be responsible for the commissioning of the TS2 Substation Equipment.

Pre-requisites: Observe a minimum of one substation commissioning by Hunt FSR.
Required Tools: Contact Hunt Technologies
Class Length: 3 days
Credits/Fee: 24 Credits / $750 per person

* Programming SPU
* Substation items
* Upstream phasing & polarity
* Installing SPU at Substation
* Configure Command Center
* Complete upstream / downstream set up
* Final documentation

Step 3:
Commissioning and Certification
The Hunt FSR will come on-site to observe utility personnel commission a substation and certify them. One Substation commissioning is required for each person being certified.

The cost for this is $5,000.00 for the first substation, and $3,000 for each additional substation if commissioned in the same week.

If you would like to attend certification training, please contact
training@hunttechnologies.com

SPU 1000/2000/3000 Optional Services Provided by Hunt Technologies CONFIDENTIAL		
Descriptions	**Part Number**	**Unit Price**
Cisco Router Configuration	**SERV-00030**	**$ 850.00**
This Service is for customers NOT hosting with Hunt Technologies. Hunt communications support will configure the Cisco 2600/2800 series Dial-up router used to call the SPU 1000/2000/3000 substation's. Cisco's 2600/2800 series router is recommended for 3 or more SPU configurations. Reconfigurations may occur as additional SPU's are added or communication changes require, and are billed accordingly. Operating temperature of 0 to 40 degrees Celsius. 32 to 104 degrees Fahrenheit, recommended for a climate controlled environment only.		
Cisco Pix Firewall Configuration, Pix 501	**SERV-00031**	**$ 350.00**
This service is for all the SPU1000/2000/3000 using Broadband connections. Hunt will configure the Cisco Pix 501 firewall. Reconfigurations may occur as additional SPU's are added or communication changes require, and are billed accordingly. Operating temperature of 0 to 40 degrees Celsius. 32 to 104 degrees Fahrenheit, recommended for a climate controlled environment only..		
Hunt Provided Cisco Router Configuration File, Example	**SERV-00032**	**$ 300.00**
Customer's can use this template file to configure the Dial-Up router internally. If additional assistance is needed, you may need to purchase Communication/Network Support at an hourly rate. Please reference SERV-00033. Reconfigurations may occur as additional SPU's are added or communication changes require. Strong IT knowledge recommended.		
Hunt Provided Cisco Pix Firewall Configuration File, Example	**SERV-00038**	**$ 200.00**
Customers can use this template file to configure the Cisco Pix 501 internally. If additional assistance is needed, you may need to purchase Communication/Network Support at an hourly rate. Please reference SERV-00033. Reconfigurations will occur as additional SPU's are added or communication changes require. Strong IT knowledge recommend.		
Hunt Provided SPU Configuration File (ini working file)	**SERV-00039**	**$ 75.00**
This is an optional service for any Command Center Software users who are using the SPU1000/2000/3000. Fee's will occur with each request. Additional fees may be incurred as additional SPU's are added or communication changes require.		
DCB Router Configuration	**SERV-00040**	**$150.00/$200.00**
$150.00 Fee includes any Command Center Software users who are installing the SPU1000/2000/3000. Reconfiguration fee's may occur as additional SPU's are added or communication changes require. $200.00 Fee includes Hunt remotely configuring at your site.		
On-Site Field Service Rep-Command Center Configuration-First Day	**SERV-00028**	**$ 2,000.00**
Each additional day	**SERV-00029**	**$ 1,000.00**
$2000 for the first day and $1000 for every additional day thereafter. Other configuration charges may apply.		
Communication/Network Support - Hourly Rate	**SERV-00033**	**$ 150.00**
Services provided by Hunt's Customer Service Communication Specialist Personnel.		
Third Party Hardware That May Need To Be Purchased Vertical Wall Mount Bracket (Black Box Corp., Part Number: RMA048) Horizontal Rack (Data Metal Craft, Inc., Hunt Part Number: FASY-0504-0003) Barfield Enclosure (Part Number: BATS282828FBSD, BATS282828FFBSE - different varieties available		

Quotation Summary

Communications: Estimated total costs do not include meters, meter installation, switches, routers, LAN modems, etc., that may be necessary to establish communications between the substations and the host computer, which will be defined after a site visit and will be your responsibility to purchase.

Hunt Technologies provides CISCO Router configuration and support services.

Typical Modes for Communication from Central Server to Substation are: Telephone(LAN), Fiber Optic, Cable Modem, Wireless Radio, Microwave and Satellite. Based upon selected Communication Media, you will be required to furnish associated equipment from a third party supplier.

Training: Command Center training is required prior to system installation. Customer receives 16 free credits during the first year of deployment.

TS2 Project Management Services: Includes project management services, pre-site evaluations, and system engineering services for 12 months. Project management services consists of coordination of entire AMI implementation and corresponding field activities that include pre-site visit, substation analysis, system engineering and design, planning of current and future deployments, development of training roadmap, management of all Hunt supplied equipment and consultation on 3rd party substation equipment, and a single point of contact to ensure introduction to Hunt's support offerings is a smooth transition on the path to system self sufficiency. System engineering services also consists of development of the communications plan, development of design layout for each substation and finalization of Hunt supplied equipment list. Project Services pricing is contingent on number of substations for entire project implementation.

After the initial 12 months, customer may choose to continue with project management services for a recurring monthly fee, may become certified in Hunt's commissioning processes via classroom training and field audit, or contact one of our preferred install providers directly. For more information on customized Project Services beyond the initial 12 months, please contact your sales coordinator.

New Customer Orientation: Includes system orientation and first substation commissioning services by Hunt's Field Services group.

Commissioning: On site field work to ensure correct installation, wiring and energizing of all substation equipment. System optimization performed via measurements and analysis completed at the substation and in the field at individual meter/endpoint locations.

Software/Hosting Options: During the initial 90 days of the system start up, Hunt will monitor the data on its server and will provide you with full access to it via web browser. At the end of the initial period, you can choose to purchase the Command Center software license and your own SQL Server and operate the system on your own or elect to purchase the monthly Command Center Managed Services Package (MSP) by signing an annual contract. On the 91st day, monthly MSP services invoicing will begin if a decision has not been made. This service will automatically be invoiced, including the communication cost from the server to the substation. The 90 day period will begin when the first substation has been commissioned.

Third Party Products: Products that customer acquires or may need to purchase that are not manufactured by Hunt or that do not display the Hunt or Landis+Gyr logo.

Standard Terms and Conditions

Warranty: Endpoints are Warranted for 18 months from date of shipment and Substation Equipment is Warranted for 12 months from date of shipment. Meters are covered under separate warranty.

Any Services Warranty, if any, will be described in the mutually signed agreement between the parties. If there is a breach of the product warranty, repair or replacement of the product is customer's sole remedy. Customer's sole remedy for a services warranty breach shall be defined in the agreement mutually signed by the parties.

Quantities Required: The actual quantities of substation equipment required will be dependent upon completed EEQ documentation and analysis of each substation during pre-site visits by Hunt.

Annual Support and Software Agreements: Hunt Technologies' Support and Software Agreements are required, and will go in to effect at the beginning of the second year of the deployment phase.

Freight and Tax: Unless otherwise stated, prices do not include freight charges, installation, or tax.

Terms: Payment Terms is Net 30 days and Quote is valid for 60 days.

Pricing: Pricing submitted on quotation may be subject to change without notification to customer.

Purchase Orders: Hunt Technologies' preferred method of receipt is fax or email detailing product description, quantity, and price. We do not accept verbal purchase orders. Purchase Orders must be issued to Hunt Technologies, LLC except for Canadian customers, then Purchase Orders must be issued to Hunt Technologies Global, Inc.

Confidentially: Information provided on Budgetary Quotations is confidential. Customer shall take all reasonable precautions to prevent such information from being divulged to third persons, including officers and employees not having legitimate need for the information.

ENGINEERING COST ESTIMATE

WORK ORDER#

Name:	GKE
Address:	
Phone:	
Fax:	
District	Engineering
Service Location	FREDONIA SUBSTATION
Permanent	
Indeterminate	
Temporary	
Seasonal	

Garkane energy

1802 South 175 East
Kanab, UT 84741
Phone: (435) 644-5026
Toll-Free (888) 644-5026
Fax: (435) 644-8120

Project Description: Install L&G TS3 receiver, TCU, and coupling transformer. Commission TS2 system in Substation

Rights-of-Way	Sent	Received
NONE Required		

ESTIMATED PROJECT COST:

ITEM	DESCRIPTION	QTY	UNIT COST	TOTAL
				$0.00
ENGINEERING FEES		25	$60.00	$1,500.00
UC1-35KV	THREE PHASE CABLE TERMINAL POLE	1	$2,540.23	$2,540.23
UG17B-35KV	THREE PHASE TRANSFORMER INSTALL	1	$2,568.73	$2,568.73
UM1-7NC	SECTIONALIZER/TRANSFORMER GROUND SLEEVE	1	$408.79	$408.79
ZUM6-10	INSULATED PROTECTIVE CAP	3	$138.17	$414.51
ZUM6-34	ELBOW ARRESTER	3	$432.29	$1,296.87
UJ2-6	TRANSFORMER CONNECTOR BLOCK	3	$498.62	$1,495.86
UM48-2	GROUND ASSEMBLY FOR MULTI PHASE TRANS.	2	$69.49	$138.98
SPECIAL	SUB STRUCTURE STEEL MODIFICATION	1	$3,500.00	$3,500.00
SPECIAL	CONCRETE PAD FOR TCU	1	$2,000.00	$2,000.00
UM50-P-2	2" CONDUIT INSTALLATION	135	$2.25	$303.75
UM50-P-3	3" CONDUIT INSTALLATION	140	$3.26	$456.40
URDWIRE-1/0CIC35K	WIRE-1/0 URD 35 KV PRIMARY JACKETED CIC	420	$5.97	$2,507.40
SPECIAL	FIBEROPTIC CABLE FROM TCU	160	$10.00	$1,600.00
75 KVA 3 PHASE PAD MOUNT TRANSFORMER 35 KV		1	$11,486.00	$11,486.00
LABOR	EXTRA LABOR	80	$60.00	$4,800.00

ESTIMATE DOES NOT INCLUDE L&G EQUIPEMENT OR LABOR

Subtotal	$37,017.52
Service Credit	
Other Credit	
Subtotal	$37,017.52
Aid in Construction	
Contract Amount	
Deposit	
AMOUNT DUE BEFORE CONSTRUCTION BEGINS.	**$37,017.52**

ESTIMATE FOR ENGINEERING PURPOSES ONLY NOT FOR CONSTRUCTION

Estimated By: Date:

General Manager Approval Date:

ATTACHMENT 16

ENGINEERING COST ESTIMATE

WORK ORDER#	

Name:	GKE
Address:	
Phone:	
Fax:	
District	Engineering
Service Location	RYAN SUBSTATION
Permanent	
Indeterminate	
Temporary	
Seasonal	

Garkane energy
1802 South 175 East
Kanab, UT 84741
Phone: (435) 644-5026
Toll-Free (888) 644-5026
Fax: (435) 644-8120

Project Description: Install L&G TS3 receiver, TCU, and coupling transformer. Commission TS2 system in Substation

Rights-of-Way	Sent	Received
NONE Required		

ESTIMATED PROJECT COST:

ITEM	DESCRIPTION	QTY	UNIT COST	TOTAL
				$0.00
ENGINEERING FEES		25	$60.00	$1,500.00
VUC1-25KV	THREE PHASE CABLE TERMINAL POLE	1	$2,340.26	$2,340.26
UG17B-25KV	THREE PHASE TRANSFORMER INSTALL	1	$2,568.73	$2,568.73
UM1-7NC	SECTIONALIZER/TRANSFORMER GROUND SLEEVE	1	$408.79	$408.79
VUM6-10	INSULATED PROTECTIVE CAP	3	$138.17	$414.51
VUM6-34	ELBOW ARRESTER	3	$432.29	$1,296.87
UJ2-6	TRANSFORMER CONNECTOR BLOCK	3	$498.62	$1,495.86
UM48-2	GROUND ASSEMBLY FOR MULTI PHASE TRANS.	2	$69.49	$138.98
SPECIAL	SUB STRUCTURE STEEL MODIFICATION	1	$3,500.00	$3,500.00
SPECIAL	CONCRETE PAD FOR TCU	1	$2,000.00	$2,000.00
UM50-P-2	2"CONDUIT INSTALLATION	100	$2.25	$225.00
UM50-P-3	3" CONDUIT INSTALLATION	80	$3.26	$260.80
URDWIRE-1/0CIC35K	WIRE-1/0 URD 35 KV PRIMARY JACKETED CIC	420	$5.97	$2,507.40
SPECIAL	FIBEROPTIC FOR TCU	130	$10.00	$1,300.00
75 KVA 3 PHASE PAD MOUNT TRANSFORMER 25 KV		1	$8,835.65	$8,835.65
LABOR	EXTRA LABOR	80	$60.00	$4,800.00

ESTIMATE DOES NOT INCLUDE L&G EQUIPEMENT OR LABOR

Subtotal	$33,592.85
Service Credit	
Other Credit	
Subtotal	$33,592.85
Aid in Construction	
Contract Amount	
Deposit	
AMOUNT DUE BEFORE CONSTRUCTION BEGINS.	**$33,592.85**

ESTIMATE FOR ENGINEERING PURPOSES ONLY NOT FOR CONSTRUCTION

Estimated By: Date:
General Manager Approval Date:

ATTACHMENT 17

ENGINEERING DEPARTMENT

DATE: 1 April 2009

TO:

FROM: Mike Avant, Engineering Manager

SUBJECT: TS1 to TS2 Conversion at Fredonia and Ryan Substations

---

Landis & Gyr has given Garkane a proposal to upgrade the existing TS1 Turtle System at the Fredonia and Ryan Substations to a TS2 Turtle System.

This upgrade will require the installation of the TS2 Receiver, TCU Coupling Unit and a dedicated 75 kVA pad mounted 3 phase main bus connected transformer (to be used for signal coupling) at each substation. In addition to the above equipment installation the following will need to be installed at each substation: 1) AC power will have to be installed to the TCU and TS2 receivers, 2) Coupling CTs will have to be installed from each circuit metering set to the TS2 receiver, 3) Fiber Optic cable must be installed between the TCU and the TS2, and 4) High speed internet service will have to be connected to each TS2 receiver through effective firewalls and routers.

Landis & Gyr has given Garkane a price of $105,126.40 for the substation equipment, software upgrade, training, installation certification, and 192 single phase meter modules. This cost does not include travel expenses of Hunt Field Service Technician to perform Commissioning or Garkane travel expenses to attend mandatory training at the Hunt Facility. These out of pocket expenses are estimated at $500 per day or 12*500=$6,000.

1802 South Highway 89A, Kanab, Utah 84741
Voice: (435)644-5026 Fax: (435)644-8120
E-mail: mavant@garkaneenergy.com

It is estimated that the Garkane installation of the Hunt supplied equipment will be $37,017.52 at the Fredonia Substation and $33,592.85 at the Paria Substation. See the attached cost estimates for a cost breakdown.

Installation of AC station service power inside of the substation to the TCU and the TS2 receiver will cost approximately $1,000 per substation.

Wireless high speed internet service is available at the Fredonia Substation from the local internet provider for an equipment fee of $195.00 and a service fee of $59.00 per month.

No commercial internet providers are currently available in the Ryan Substation area. We can install a SPACENET satellite dish at this location and use it to obtain internet service as we have at Henrieville, Hatch, Todds and Paria Substations. The Spacenet equipment cost is $1,600. The concrete pad, cables, lightning protectors and labor has averaged $1,000 at other locations where we have installed this equipment. The monthly fee from Spacenet is $39.00 per month per location.

High speed internet service will also require the installation of firewalls and routers to facilitate and protect the communications between the receiver and the internet modem. The router/firewall currently used by Garkane computer technicians cost $600 each.

Hunt specifies a list of tools required to install and maintain the equipment. Most of the items we already have. Two pieces of test equipment which we do not have are the Fluke 1587 ($622) and the B&K 878B ($249). AFL also recommends a Black Box FT730A Fiber Optic Maintenance Kit ($2,195.95) with a FT731 adapter ($265.95) to install and test the fiber optic cable.

The total cost to upgrade the existing TS1 systems at Fredonia and Ryan Substations is estimated at:

Landis & Gyr Cost	$105,126.40
Out of pocket expenses	$6,000.00
Fredonia installation cost	$37,017.52
Ryan installation cost	$33,592.85
AC power installation	$2,000.00

Internet Service	$2,795.00
Monthly cost- $98.00	
Router and Firewalls	$1,200.00
Specialized Test Equipment	$3,332.90
Total Installation Cost	$191,064.67
Monthly Internet Cost	$98.00

Stellar Grants has a contract with Landis+Gyr to assist customers in the application for a Smart Grid ARRA grant. These grants may be available on a matching funds basis to cover up to ½ of the cost of implementing smart grid technology. The cost of having Stellar prepare and apply for a grant in behalf of Garkane is $20,400.

Stellar Grants

MASTER CONSULTING AGREEMENT

THIS AGREEMENT BECOMES EFFECTIVE UPON 1] Agreement Execution, and 2] Payment and Clearance of the first payment due as indicated within the Customer Project Attachment [CPA]. This Agreement shall become invalid 14 days after issuance if agreement execution and payment have not been effected.

This Master Consulting Agreement for professional services (the "Agreement"), effective on the date indicated within the execution section, and is by and between:

Stellar Grants, Inc.	**Garkane Energy Cooperative, Inc.**
(herein the 'consultant')	**(herein the 'Customer')**
With its principal office at:	**With its principal office at:**
2106 Meadow Parkway North,	**P.O. Box 465**
League City	**Loa**
Texas	**Utah**
TX 77573	**UT 84747**

WHEREAS, Client finds that the Company is willing to perform certain work hereinafter described in accordance with the provisions of this Agreement; and

WHEREAS, Client finds that the Company is qualified to perform the work, all relevant factors considered, and that such performance will be in furtherance of Client's business.

NOW, THEREFORE, in consideration of the mutual covenants set forth herein and intending to be legally bound, the parties hereto agree as follows:

Agreements and Documents.

I. **Type of Agreement. This Agreement is a Master Agreement which provides the general provisions governing the Consulting Services set forth in any Customer Project Attachment to this Agreement. No party hereto, by reason of entering into this Agreement or otherwise, is obligated to enter into any Project Attachment.**

II. **Project Attachments and Orders. Any specific Consulting Services to be performed by Consultant shall be agreed upon by means the parties entering into a Project Attachment with Consultant. Upon entering into a Customer Project Attachment, a "Project" under this Agreement shall exist. The Customer Project Attachment shall fully set forth the consulting services to be performed ("Consulting Services"), during which time periods, at what locations, utilizing which personnel of Consultant, the fees and expenses to be paid to Consultant, and other relevant information for the Project.**

1. ***Consulting Services.***

   1) **Performance of Consulting Services. Consultant shall perform the consulting services specified in each Project Attachment pursuant to the provisions thereof and the provisions of this Agreement. Further, Consultant shall provide to Customer any deliverables specified in a Project Attachment as part of such Consulting Services. Consulting Services shall be performed in a professional and workman-like manner consistent with industry standards.**
   2) **Consultant's Personnel. Consultant shall be fully responsible and liable to Customer for the compliance of Consultant's employees, agents, and other personnel with Consultant's obligations under this Agreement.**
   3) **Compliance with Rules. Consultant shall comply with Customer rules, policies, standards, and procedures (including without limitation work place rules) in connection with Consultant's performance of the Consulting Services. In addition, if a Project requires Consultant's personnel to be**

at the location of any other party, then Consultant shall comply with the rules, policies, standards, and procedures (including without limitation work place rules) of such third party while located there.

4) Compliance with Laws. Consultant shall comply with all applicable laws in connection with Consultant's performance of the Consulting Services.

5) Reporting. Consultant will promptly furnish to Customer a record of any and all writings, and improvements relating to any Project which are conceived or reduced to practice during the term of this Agreement, whether patentable or not, which are suggested by or result from work done on behalf of Customer.

2. *General Payment Provisions*

1) Invoices and Payment. Consultant shall invoice for all Consulting Services and related deliverables in accordance with the terms of the Project Attachment. All payments hereunder are due as defined therein. The fees and reimbursements specified in a Project Attachment are the sole and exclusive compensation due to Consultant from Customer hereunder, and under this Agreement. Consultant shall not be obligated to perform work services until payments have been made in accordance with the CPA.

2) Expenses. Expenses of Consultant are only reimbursable by Customer if authorized in a Project Attachment. If so authorized, expenses are only reimbursable (a) if the expenses are authorized by Customer in writing in advance, (b) if they are customary and reasonable in amount, and (c) if Consultant submits a report of the expenses, along with original receipts for each expense, to Customer within 30 calendar days of incurring the expense. Except for costs and expenses specifically assumed by a party under this Agreement or a Project Attachment.

3. *Term.*

1) Basic Term. This Agreement shall commence on the date set forth in the Preamble hereof and shall remain in effect unless terminated as provided in Section 4.2.

2) Early Termination Events.

I. This Agreement may be terminated at any time by the mutual written consent of Customer and Consultant.

II. This Agreement may be terminated by a party upon its written notice of termination to the other parties based on a Default by one of the parties. A party shall be deemed to be in "Default" of this Agreement if such party has breached or otherwise failed to observe an obligation imposed upon such party by this Agreement, and such breach has continued unremedied for a period of at least thirty (30) days following another party's written notice to such party that such breach or failure occurred if capable of cure, or immediately if not capable of cure.

III. This Agreement may be terminated by a party upon its written notice of termination to the other parties based on the Bankruptcy of one of the parties. A party shall be deemed to be in "Bankruptcy" for purposes of this Agreement (i) if such party shall be the subject to a bankruptcy filing, (ii) upon the appointment of a receiver, liquidator, assignee, custodian, trustee, sequestrator, or other similar agent for such party, or (iii) upon the institution of similar proceedings to any of the foregoing with respect to such party.

IV. Project Terminations. In the event that there is a Default with respect to a Project under this Agreement, then the non-defaulting party may (at its election) terminate that Project without terminating this Agreement because of such Default and exercise its remedies.

4. *Confidentiality and Non-Disclosure*

1) Confidentiality Obligations. Required Disclosures. The Consultant may disclose such information in the fulfillment of all obligations as identified in any CPA. Accordingly client may use information provided by Customer, and copy and/or disseminate such information of fulfilling its obligations under any CPA.

2) Restricted Use: Company shall: (a) use the Client's Confidential Information only in connection with providing the Services detailed herein; (b) disclose the Client's Confidential Information only to its

officers, directors, employees and advisors who need to know the Client's Confidential Information to accomplish the objective of the Services; and (c) safeguard the Client's Confidential Information with the same degree of care to avoid unauthorized disclosure as Company uses to protect its own Confidential Information of a similar nature; but in no case less than reasonable care. It is Company's responsibility to ensure that any officers, directors, or employees to have access to the Client's Confidential Information will, prior to being provided with any or all of the Client's Confidential Information, agree to be bound by the terms of this Agreement.

3) **Nondisclosure: Company will hold all of the Client's Confidential Information in strict confidence and, except as expressly set forth herein, will not disclose such Confidential Information to any third parties (which term as used in this Agreement will be broadly interpreted to include without limitation to any corporation, company, group, partnership, agency, or individual), except in the fulfillment of its duties where it is acknowledged by the client that the company must disclose such information to fulfill its duties, and the client approves and authorizes such disclosure to be made at the company's discretion.**
4) **Restricted Use: Company shall: (a) use the Client's Confidential Information only in connection with providing the Services detailed herein; (b) disclose the Client's Confidential Information only to its officers, directors, employees and advisors who need to know the Client's Confidential Information to accomplish the objective of the Services; and (c) safeguard the Client's Confidential Information with the same degree of care to avoid unauthorized disclosure as Company uses to protect its own Confidential Information of a similar nature; but in no case less than reasonable care. It is Company's responsibility to ensure that any officers, directors, or employees to have access to the Client's Confidential Information will, prior to being provided with any or all of the Client's Confidential Information, agree to be bound by the terms of this Agreement.**
5) **Consultant Authorized Usage of Information: Client authorizes the company to release any information, and/or documentation relating to the client and/or its activities, and/or its financials in the fulfillment of its duties as described herein.**
6) **Non-Circumvention; The parties herein, do hereby and with full intention of being legally bound, do hereby irrevocably agree not to circumvent, avoid, bypass, or obviate each other, directly or indirectly, to avoid payment of fees or other benefits in any transaction with any corporation, partnership, or individual/s, revealed by either party to the other (excluding those previously known in an existing business relationship prior to this Agreement). This shall apply to any project, including the purchase and sale of real estate, strategic development, or currency exchange, or any loans, or collateral, or funding/s, or addition, renewal, extension, rollover, amendment, renegotiation, new contracts, parallel contracts/agreements, commissions, or third party assignments thereof.**
7) **Prior NDAs. If Consultant and Customer have entered into a nondisclosure or confidentiality agreement prior to the Effective Date, such prior agreement shall govern the nondisclosure and confidentiality of Confidential Information prior to the Effective Date and this Agreement shall govern on and after the Effective Date with respect to this Agreement and its subject matter.**

5. *Property Rights.*

1) **Indemnification. Consultant shall, at its expense, defend, indemnify, and hold Customer, Customer affiliates, and Customer's and Customer affiliates' personnel and Customers (collectively, "Indemnified Parties"), harmless from and against any claim, action, suit, or allegation based on a claim that any of the Consulting Services and Consulting Services deliverables infringes a domestic or foreign patent, trademark, or copyright, or misappropriates a trade secret, of a third party, and shall, notwithstanding any limitations on or exclusions from liability for damages set forth in this Agreement, pay all damages, losses, costs, and expenses, including, without limitation, reasonable attorneys' fees and court costs, that an Indemnified Party incurs or are awarded against an Indemnified Party. Consultant shall not enter into any settlement that affects an Indemnified Party's rights or interests without Customer's prior written approval. Customer agrees that an Indemnified Party will provide such assistance and cooperation as is reasonably requested by Consultant or its counsel in connection with any such claim, action, suit, or allegation.**

6. *Warranties.*

1) Each party hereto represents to the other party hereto that it (a) has all rights necessary to enter into and to fulfill its obligations under this Agreement and each Customer Project Attachment, and (b) has no knowledge of any adverse claim against or adversely affecting such rights. Consultant warrants to Customer that all Consulting Services and deliverables shall conform in all material respects to the specifications and requirements provided by Customer. Consultant warrants that all Consulting Services and Consulting Services deliverables shall be performed with care, skill, and diligence and in a professional and workman-like manner, consistent with industry standards. Consultant warrants that all goods, equipment, and materials which it supplies in connection with the Consulting Services and Consulting Services deliverables shall be of good quality and shall be free from defects in materials and workmanship. Consultant shall promptly correct any non-conformities with the warranties set forth in this Section 7 at no additional cost or expense to Customer.

7. ***Excluded Liabilities.***

1) EXCEPT WITH RESPECT TO OBLIGATIONS UNDER SECTIONS 5 AND 6 HEREOF, No party hereto shall have any liability to another party hereto for indirect, consequential, incidental, special, punitive, or exemplary damages (even if advised of the possibility of such damages), including without limitation damages resulting from loss of use, loss or corruption of data, loss of revenue, loss of profit, LOSS OR DAMAGE TO GOODWILL, LOSS OF SAVINGS (REAL OR ANTICIPATE), or loss of business, whether arising out of or in connection with the performance of the CONSULTING services, CONSULTING services deliverables, or any other means, and regardless of the form of action upon which a claim for such damages may be based, whether in contract, tort (including negligence), strict product liability, or any other legal or equitable theory. These limitations shall apply even if any limited remedy fails in its essential purpose.

8. ***Consultant Provisions***

1) NO GUARANTEES. Stellar Grants, Inc. neither makes nor implies herein, nor in any of its actions, a guarantee that any business proposal/s, grant/s and/or RFP/s, or application/s or submission/s or introduction will result in the customer achieving the acquisition of funds, and/or any other benefit/s.
2) NO REFUNDS. The Consultant offers no refunds for RFP/grants/business proposals, and funds it receives from customer.
3) NO LIABILITY ON SUBMISSIONS. Additionally the Consultant shall not be liable in any manner whatsoever for submissions it prepares, nor shall the Consultant be responsible should the Customer not be awarded or granted any fund/s and/or benefit from the company's work product. IT IS INCUMBENT ON THE CUSTOMER TO PROVIDE FINAL APPROVAL ON ALL WORK PRODUCTS PRIOR TO ANY SUBMISSIONS TO THE PROSPECTIVE FUND GRANTOR.

9.. ***Miscellaneous***

1) Agreement. This Agreement includes any exhibit and schedule hereto and any Customer Project Attachment issued hereunder, constitutes the entire agreement among the parties hereto with respect to the subject matter hereof, and supersedes all prior oral or written agreements, commitments, acknowledgements, representations, and/or understandings with respect to the matters provided for herein. This Agreement shall be binding upon and shall inure to the benefit of the parties hereto and to their respective permitted assigns and successors. The rights and remedies provided herein shall be cumulative and not exclusive of any rights or remedies provided by law.
2) Assigns. It is the explicit intention of the parties hereto that no person or entity other than the parties hereto and their permitted assigns and successors is or shall be entitled to bring any action to enforce any provision of this Agreement against any of the parties hereto, and that the covenants, undertakings, and agreements set forth in this Agreement shall be solely for the benefit of, and shall be enforceable only by, the parties hereto and their permitted assigns and successors.
3) Amendment. No amendment, modification, or discharge of this Agreement, and no waiver hereunder, shall be valid or binding unless set forth in a writing signed by the parties.
4) Waiver. Neither the waiver by any of the parties hereto of a breach of or a default under any of the provisions of this Agreement, nor the failure of any of the parties, on one or more occasions, to enforce any of the provisions of this Agreement or to exercise any right or privilege hereunder shall

thereafter be construed as a waiver of any subsequent breach or default of a similar nature, or as a waiver of any such provision, right or privilege hereunder.

5) Assignment and Subcontracting. Consultant acknowledges that Customer has entered into this Agreement based on the particular qualities and abilities of Consultant and its staff which may or may not be in the form of sub-contractor relationships. Consultant may assign either this Agreement and/ or any Project Attachment to subcontract or delegate any of its obligations under this Agreement or any Project Attachment without the prior written consent of Customer, subject that the Consultant shall manage and supervise any work being sub-contracted in accordance with the terms of this Agreement and/or any CPA.

6) Deadlines. The Company shall use its best endeavors to meet the deadlines established by individual grant and/or funding sources. It is acknowledged by the client that it is the client's responsibility to furnish sufficient information to the company in a timely manner to enable the company to respond in a professional and effective manner to the deadlines established by aforementioned funding sources. This information shall include, but not be limited to, information relating to the company/organization, its activities, products and services, financial data, management and key personnel, references and collaboration letters, as well as any technical details required to support it funding application, and other requirements provided by the company during the fulfillment of its duties. In the event that the company does not provide full detailed information as required by such applications, within ample timeframes provided by the company, then the company shall neither be responsible for, nor be liable for any failure or resulting consequence, monetary or otherwise, for not meeting such deadline/s.

7) Equitable Relief. Each of the parties hereto acknowledges and agrees that irreparable loss and damage will be suffered (i) by another party hereto if such party should breach or violate any of the covenants and agreements contained in Sections 5 and 6, and the parties therefore agree and consent that, in addition to any other remedies available to them, each party hereto shall be entitled to an injunction and other equitable relief to prevent a breach or contemplated breach by another party hereto with respect to those provisions of this Agreement.

8) Governing Law and Forum Selection. This Agreement, the rights and obligations of the parties hereto, and any claims or disputes relating thereto, shall be governed by and construed in accordance with the laws of the State of Texas, USA (but not including the choice of law rules thereof) and any applicable federal laws of the USA. The parties hereto hereby irrevocably consent to the jurisdiction and venue of any federal or state court in the State of Texas USA or, at the choice of Customer, of any court in the State or Country of Consultant's location, with respect to any action by Customer.

9) Independent Contractors. The relationship between and among the parties hereto is that of independent contractors only. Nothing in this Agreement shall be construed so as to constitute any party as a partner or joint venturer of another party, or any party hereto as the employee or agent of any other party hereto, or in any other manner other than as independent contractors. No party shall have any power or authority to bind another party in any transaction with a third party, and no party shall hold itself out to third parties as having any such power or authority.

10) Notices. All notices, demands, requests, or other communications that may be or are required to be given, served, or sent by any party to any other party pursuant to this Agreement shall be in writing and shall be (i) mailed by first class certified mail, postage pre-paid, return receipt requested, (ii) transmitted by hand delivery (including hand delivery through an internationally recognized over-night delivery service which provides confirmation of delivery, such as Federal Express, UPS, or DHL), or (iii) transmitted by facsimile if simultaneously sent by the method specified herein, in each case to the applicable address and facsimile number set forth on the signature page of this Agreement.

11) Severability. If any part of any provision of this Agreement shall be invalid or unenforceable under applicable law, said part shall be ineffective to the extent of such invalidity or unenforceability only, without in any way affecting the remaining parts of said provision or the remaining provisions of the Agreement.

12) Survivability. Any provision of this Agreement or a Project Attachment which by its very nature or context is intended to survive any termination or expiration thereof, including without limitation the provisions of Sections 5, 6, 7, 8, and 9 of this Agreement,, shall so survive such termination or expiration.

IN WITNESS WHEREOF, the parties have caused this Agreement to be executed on their behalf by their duly authorized representative as of the Effective Date.

By and For The Customer

Carl Albrecht
General Manager/CEO
Garkane Energy Cooperative, Inc.

Effective Date: 4/7/2009

By and For The Consultant

Kimberly Fontenot
President
Stellar Grants, Inc.

Effective Date: 4/7/2009

As Witnessed By:

Paul Johnson
President
Stellar Business Group, Inc.

CUSTOMER PROJECT ATTACHMENT

THIS AGREEMENT BECOMES EFFECTIVE UPON 1] Agreement Execution, and 2] Payment and Clearance of the first payment due as indicated herein. This Agreement shall become invalid 14 days after issuance if agreement execution and payment have not been effected.

This Customer Project Attachment [CPA] for professional services (the "CPA Agreement"), is effective on the first date indicated herein, and is entered into by and between:

Stellar Grants, Inc.	**Garkane Energy Cooperative, Inc.**
(herein the 'Consultant')	***(herein the 'Customer')***
With its principal office at:	**With its principal office at:**
2106 Meadow Parkway North,	**P.O. Box 465**
League City	**Loa**
Texas	**Utah**
TX 77573	**UT 84747**

THIS CUSTOMER PROJECT ATTACHMENT SHALL BE: CPA #GAR 4101

PEREAMBLE

WHEREAS, Customer finds that the Consultant is willing to perform certain work hereinafter described in accordance with the provisions of this Agreement; and

WHEREAS, Customer finds that the Consultant is qualified to perform the work, all relevant factors considered, and that such performance will be in furtherance of Customer's business.

NOW, THEREFORE, in consideration of the mutual covenants set forth herein and intending to be legally bound, the parties hereto agree as follows:

NOW THEREFORE, the parties hereto, for good and valuable consideration, the sufficiency of which is hereby acknowledged, and intending to be legally bound, do hereby agree as follows:

1. **Project Attachment. This is a Customer Project Attachment as defined in the Master Consulting Agreement between the Customer and Consultant. This CPA is governed by the provisions of such Master Consulting Agreement. Capitalized terms not otherwise defined herein shall have the meaning set forth in the Master Consulting Agreement.**
2. **Reference to"$" as used herein refers to U.S. dollars. All transactions shall be in U.S. dollars. Unless otherwise guaranteed in writing. Project.**
3. **This CPA is for Consulting Services as set forth as follows:**
   a) **PROJECT TITLE: Customer desires the Consultant to assist in the development of opportunities presented by and through the ARRA Act of 2009, better known as the Stimulus Package.**
   b) **Within that package there are specific sections relating to the 'Smart Grid' and therein, detailed grant releases that will be relevant to the customer's business operations**
   c) **Client Focus: AMI opportunities. Client wishes the Consultant to focus on the potential within the ARRA that can provide impact through grants relating to AMI or other such Smart Grid opportunities it may so select at its discretion**
   d) **In that respect there are a series of services and deliverable to be provided. These are itemized on the following chart in each one of 3 stages together with a costing estimate for each stage.**

ARRA GRANT PROCESS
The following estimate is based on a 3 stage process:

Grant Project Estimate

Stage 1		
	Registration	**$ zero: provided by customer**
Stage 2		
	Project Development	
	From provision by customer- ,technical and financial information provided by client: Grant Preparation, grant writing to approval process	**$ 16,000.00**
Stage 3		
	Grant Submission, follow-up through tracking and monitoring	**$ 2,400.00**
	Total: Estimate	**$ 18,400.00**

STAGE 1; Grant Applicant Services - Registration

To:

1. **Prepare all customer details and other necessary information for entry into registration process**
2. **For each of the main government agencies that form part of the requirements for the Grants process, including : DUNS, CCR with NAICS and SIC criteria, AOR/POC, ORCA Registration, FAR/GSA Schedule entry, www.grants.gov to take the following actions: 1} Verify and validate status of customer's company, and 2] where relevant, register company into each one in order to facilitate entry by the customer into the grant process.**
3. **Register Stellar Grants, Inc as AOR/POC if Stellar Grants is to liaise, and/or submit application/s and/or provide follow-up to the customer and the respective agencies**

Cost: $ zero: Provided by customer

STAGE 2; Grant Applicant Services -Grant Writing & Preparation of Master

To:

1. **Receive customer documentation and review against final grant application requirements. Work with customer to establish full response needs**
2. **Preliminarily research applicable grant opportunities, receive customer background documentation to include, but not be limited to; business plan, grant objectives, description of grant project, staff assigned, financials, mission/objective**

narrative for grant purposes, bios on all applicable staff, land/ source area description, Smart Grid growth and development, structuring and strategies to the intended proposal etc.

3. This stage will include multiple meetings, and/or discussions with client contact/s
4. Preparation and writing of a Master for the Customer. Customer to provide all technical matter in conjunction with financials relating to supporting their requirements and strategy.
5. During preparation of the preparation Consultant shall conduct further research to ascertain potential for other relevant opportunities
6. Upon completion of writing the Master grant, this shall be presented to customer for their approval. Upon such approval the Consultant shall prepare the final submission in readiness for the Application process.

Estimate Cost: $16,000.00

STAGE 3; Submit Application, Tracking, Monitoring, & Follow-up process

To;

1. Submit Application through www.grants.gov or other appointed agency.
2. Thereafter, follow-up with RFP/grant officer/s and/or committee members through tracking system (if applicable), or network with associated staff for feedback
3. Liaise with customer, provide status reports, prepare and submit any follow-up documentation requested by grant officer and/or grant committee review board if applicable
4. Submit any reporting requirements, needed to receive the grant award.

Estimate Cost: $2,400.00

NOTE:

These costs apply to the preparation of one Master and one submission-and subsequent follow-though as defined in Stage 3 above.

In the event that through research conducted for customer, customer-at their sole discretion-wishes to apply for further grant opportunities then should the grant needs be fulfilled by that prepared Master, each additional grant shall cost a further $1,000.00 for the Stage 3 work process.

It shall be incumbent for the customer to provide detailed financials that can be used to facilitate the grant Application requirements.

OTHER GRANTS

In the event that Customer wishes to make applications for other grants that fall outside the confines of the Master previously produced, then the parties shall discuss and agree any *further costs* prior to committing for an additional program. A new CPA shall be raised and executed that facilitates the deliverables with respect to that additional requirement.

e) **Payments; All work produced by the Consultant are payable in advance of production of work products.**

f) **Payment Schedules. Payments can be made by the customer in the following manner, and at their discretion; Option 1: Payment on Agreement, or Option 2: Payment of 50% on Agreement, and thereafter the balance of 50% following mid-point timing of Stage 2**

g) **Performance Commissions: There are no Performance Commissions for this Project.**

h) **Consultant Hourly Rate; The hourly rate being provided is $125.00 for the performance of deliverables as defined herein. Total fees shall not be exceeded save with the express approval of the Customer**

i) **Expenses: Customer agrees to reimburse consultant for reasonable travel, hotels, and incidental costs incurred within the performance of this Project Attachment. These are payable within 14 days on invoice from the Consultant.**

IN WITNESS WHEREOF, the parties have caused this Agreement to be executed on their behalf by their duly authorized representative as of the Effective Date.

By and For The Customer	By and For The Consultant
Carl Albrecht	Kimberly Fontenot
General Manager/CEO	President
Garkane Energy Cooperative, Inc.	Stellar Grants, Inc.
Effective Date: 4/7/2009	Effective Date: 4/7/2009
	As Witnessed By:
	Paul Johnson
	President
	Stellar Business Group, Inc.

468 N. US HWY. 89, HATCH, UT 84735
PO BOX 511, HATCH, UT 84735
(435) 735-4288 TOLL-FREE (888) 735-4288
FAX (435) 735-4312

Fax

Garkane energy

To: Mike Avant
From: Craig T.
Fax:
Date: 4-8-09
Phone:
Pages: 3 Including cover page
Re:
CC:

☐ Urgent ☐ For Review ☐ Please Comment ☐ Please Reply ☐ Please Recycle

•Comments: Meter Quote From Northern Power
L+G Meters

ATTACHMENT 20

craig this is my price on the meters

WAYNE FELIX
NORTHERN POWER EQUIPMENT

Subject: RE: Meter Quote for Arizona Corporation Commission.doc
Date: Tue, 31 Mar 2009 13:17:12 -0600
From: john@hadenver.com
To: waynenorthernpower@hotmail.com

From: Wayne Felix [mailto:waynenorthernpower@hotmail.com]
Sent: Monday, March 30, 2009 9:01 AM
To: John Schmidt
Subject: FW: Meter Quote for Arizona Corporation Commission.doc

john will you please quote for craig at garkane

WAYNE FELIX
NORTHERN POWER EQUIPMENT

From: ctwitchell@garkaneenergy.com
To: waynenorthernpower@hotmail.com
Subject: Meter Quote for Arizona Corporation Commission.doc
Date: Fri, 27 Mar 2009 13:45:12 -0600

Wayne,
Please fax or e-mail me a written quote on the enclosed list of meters, that we can use in a fileing with the arizona corp comm.
Thanks
Craig Twitchell
Garkane energy
Hatch office
ctwitchell@garkaneenergy.com

Meter Quote for Arizona Corporation Commission

Please submit written quote for the following items.

Item Description	Quantity	
1 Phase, Residential electronic meter, Form 2S, Cl 200, With L+G TS1 Endpoint, capable of Net metering. $362.14	1 AXS4e2SW/TS1	362.14
1 Phase, Residential electronic meter, Form 2S, Cl 200, With L+G TS1 Endpoint, capable of TOU metering. NET+TOU $369.	1AXS4e2Sw/TS1,	369.00
1 Phase, Commercial electronic meter, with Demand register, Form 2S, Cl 200, With L+G TS1 Endpoint, capable of Net metering. $362.14	1 "	398.00 "
1 Phase, Commercial electronic meter, with Demand register, Form 2S, Cl 200, With L+G TS1 Endpoint, capable of TOU metering. $369	1 "	410.00 "
3 Phase, Commercial electronic meter, with Demand register, Form 16S, Cl 200, With L+G TS1 Endpoint, capable of Net metering. $362.14	1	398.00
3 Phase, Commercial electronic meter, with Demand register, Form 16S, Cl 200, With L+G TS1 Endpoint, capable of TOU metering. $369	1	410.00
1 Phase, Commercial electronic meter, with Demand register, Form 3S & 4S, Cl 20, With L+G TS1 Endpoint, capable of Net metering. $362.14	1	398.00
1 Phase, Commercial electronic meter, with Demand register, Form 3S & 4S, Cl 20, With L+G TS1 Endpoint, capable of TOU metering. $369	1	410.00
3 Phase, Commercial electronic meter, with Demand register, Form 9S, Cl 20, With L+G TS1 Endpoint, capable of Net metering. $362.14	1	398
3 Phase, Commercial electronic meter, with Demand register, Form 9S, Cl 20, With L+G TS1 Endpoint, capable of TOU metering.	1	398 ~~$369.12~~ 398.00

NOTE: With TS1 in order to do Net Metering for single phase or three phase the AXS4e has to be used

21

Mike Avant

From: Craig M. Twitchell [ctwitchell@garkaneenergy.com]
Sent: Monday, April 13, 2009 8:52 AM
To: Mike Avant
Subject: Meter Quote for Arizona Corporation Commission.doc

Wayne,
Please fax or e-mail me a written quote on the enclosed list of meters, that we can use in a fileing with the arizona corp comm.
Thanks
Craig Twitchell
Garkane energy
Hatch office
ctwitchell@garkaneenergy.com

Prices for GE Meters

All meters would need to be KV2C type meters with TS1 endpoints. They would also require Net metering or TOU software switches. The Price would be $425.00 per meter.

Meter Quote for Arizona Corporation Commission

Please submit written quote for the following items.

Item Description	Quantity	Price
1 Phase, Residential electronic meter, Form 2S, Cl 200, With L+G TS1 Endpoint, capable of Net metering.	1	425.00
1 Phase, Residential electronic meter, Form 2S, Cl 200, With L+G TS1 Endpoint, capable of TOU metering.	1	425.00
1 Phase, Commercial electronic meter, with Demand register, Form 2S, Cl 200, With L+G TS1 Endpoint, capable of Net metering.	1	425.00
1 Phase, Commercial electronic meter, with Demand register, Form 2S, Cl 200, With L+G TS1 Endpoint, capable of TOU metering.	1	425.00
3 Phase, Commercial electronic meter, with Demand register, Form 16S, Cl 200, With L+G TS1 Endpoint, capable of Net metering.	1	425.00
3 Phase, Commercial electronic meter, with Demand register, Form 16S, Cl 200, With L+G TS1 Endpoint, capable of TOU metering.	1	425.00
1 Phase, Commercial electronic meter, with Demand register, Form 3S & 4S, Cl 20, With L+G TS1 Endpoint, capable of Net metering.	1	425.00
1 Phase, Commercial electronic meter, with Demand register, Form 3S & 4S, Cl 20, With L+G TS1 Endpoint, capable of TOU metering.	1	425.00
3 Phase, Commercial electronic meter, with Demand register, Form 9S, Cl 20, With L+G TS1 Endpoint, capable of Net metering.	1	425.00

ATTACHMENT 21

3 Phase, Commercial electronic meter, with Demand register, Form 9S, Cl 20, With L+G TS1 Endpoint, capable of TOU metering.	1	425.00

Mike Avant

From: Craig M. Twitchell [ctwitchell@garkaneenergy.com]
Sent: Wednesday, April 08, 2009 8:20 AM
To: Mike Avant
Subject: FW: Meter Quote for Arizona Corporation Commission.doc

-----Original Message-----
From: Ross Howells [mailto:ross@ritereng.com]
Sent: Wednesday, April 01, 2009 11:27 AM
To: 'Craig M. Twitchell'
Subject: RE: Meter Quote for Arizona Corporation Commission.doc

Hello Craig,
Itron can only do TS2 in three phase.
There is a external collar product by Turtle Hunt that can be used and it is tied to the KYZ out put of the meter.
Itron does not offer single phase net, TOU, demand
Sincerely,
Ross

From: Craig M. Twitchell [mailto:ctwitchell@garkaneenergy.com]
Sent: Friday, March 27, 2009 1:31 PM
To: ross@ritereng.com
Subject: Meter Quote for Arizona Corporation Commission.doc

Ross,
Please fax or e-mail me a quote on the enclosed list of meters, that we can use in a fileing with the arizona corp comm.
Thanks
Craig Twitchell
Garkane energy
Hatch office

Meter Quote for Arizona Corporation Commission

Please submit written quote for the following items.

Item Description	Quantity
1 Phase, Residential electronic meter, Form 2S, Cl 200, With L+G TS1 Endpoint, capable of Net metering.	1
1 Phase, Residential electronic meter, Form 2S, Cl 200, With L+G TS1 Endpoint, capable of TOU metering.	1
1 Phase, Commercial electronic meter, with Demand register, Form 2S, Cl 200, With L+G TS1 Endpoint, capable of Net metering.	1
1 Phase, Commercial electronic meter, with Demand register, Form 2S, Cl 200, With L+G TS1 Endpoint, capable of TOU metering.	1

ATTACHMENT 22

3 Phase, Commercial electronic meter, with Demand register, Form 16S, Cl 200, With L+G TS1 Endpoint, capable of Net metering. 1

3 Phase, Commercial electronic meter, with Demand register, Form 16S, Cl 200, With L+G TS1 Endpoint, capable of TOU metering. 1

1 Phase, Commercial electronic meter, with Demand register, Form 3S & 4S, Cl 20, With L+G TS1 Endpoint, capable of Net metering. 1

1 Phase, Commercial electronic meter, with Demand register, Form 3S & 4S, Cl 20, With L+G TS1 Endpoint, capable of TOU metering. 1

3 Phase, Commercial electronic meter, with Demand register, Form 9S, Cl 20, With L+G TS1 Endpoint, capable of Net metering. 1

3 Phase, Commercial electronic meter, with Demand register, Form 9S, Cl 20, With L+G TS1 Endpoint, capable of TOU metering. 1

GARKANE ENERGY COOPERATIVE, INC.
ELECTRIC SERVICE

SCHEDULE NO. 33

STATE OF ARIZONA

PROPOSED

NET METERING SERVICE

APPLICABILITY: Applicable to "Net Metering Facility" as defined in Rule R14-2-2302, which meet ALL of the following conditions:

1. Generator must be installed at a service receiving electric service on or adjacent to the customer's Primary Service, subject to the company's service requirements. (Primary Service).
2. Generator must be incidental to the Primary Service, installed on the customer's premises, and used to supply some or all of the customer's loads.
3. Generator capacity shall not be more than 125% of the Net Metering Customer's connected load.
4. Generator must have a maximum output of less than 10% of the nearest source side primary voltage protective device, and must be less than 80% of the installed transformer capacity at the Primary Service..
5. Generator must have the same output voltage and phasing as the Primary Service.
6. Generator must be a fuel cell, combined heat and power or other renewable energy powered generator controlled by an inverter which has been designed, tested, and UL certified to UL1741 and IEEE1547 standards.
7. Generator must have positive "anti islanding" capability per UL1741.
8. Generator must have output voltage with less than 1% Total Harmonic Distortion (THD), current output with less than 2% THD, and be operated with a 1.0 to .95% lagging Power Factor. Leading power factor operation will not be permitted.
9. Generator must be provided with a "Visible Disconnect Switch" per NESC requirements which can be padlocked in the OPEN position and is accessible to Garkane personnel at all times. Disconnect must be permanently and visibly marked as "GENERATOR DISCONNECT" in letter at least 2" high.
10. The electrical function, operation, or capacity of a customer generation system, at the point of connection to the electrical corporation's distribution system, may not compromise the quality of service to the electrical corporation's other customers.

BILLING FOR NET METERING (In accordance with Rule R14-2-2306):

a. On a monthly basis, the Net Metering Customer shall be billed or credited based upon the rates applicable under the customer's currently effective standard rate schedule and any appropriate rider schedules.
b. If the kWh supplied by the Company exceed the kWh that are generated by the Net Metering Facility and delivered back to the Cooperative during the billing period, the Customer shall be billed for the net kWh supplied by the Cooperative in accordance with the rates and charges under the Customer's standard rate schedule.
c. If the electricity generated by the Net Metering Customer exceeds the electricity supplied by the Company in the billing period, the Customer shall be credited during the next billing period for the excess kWh generated. The excess kWh during the billing period will be used to reduce the kWh supplied (not kW or kVA demand or customer charges) and billed by the Cooperative during the following billing period.
d. Customers taking service under time-of-use rates who are to receive a credit in a subsequent billing period for excess kWh generated shall receive such credit during the next billing period during the on- or off-peak periods corresponding to the on- or off-peak periods in which the kWh were generated by the Customer.
e. Once each calendar year the Cooperative shall issue a check or billing credit to the Net Metering Customer for the balance of any credit due in excess of amounts owed by the Customer to the Cooperative. The payment for any remaining credits shall be at the Cooperative's avoided cost as shown below:

Energy Credit	$0.0165 per kWh
On Peak Demand Credit	$7.50 per kW (for Time-of-Use Rate customers only)

MINIMUM: The minimum monthly charge shall be as stated in the applicable standard rate schedule, and any increase required under the Line Extension Policy.

ATTACHMENT 23

TEMPORARY DISCONTINUANCE OF SERVICE: If a consumer requests reconnection of service at the same location, he shall be required to pay the applicable Base Rate for each of the intervening months. Non-use of service for 12 months shall make the premises subject to removal under the Idle Service Regulation.

ELECTRIC SERVICE REGULATIONS: Service under this schedule will be in accordance with the above conditions and the Electric Service Agreement between the customer and the Association. The Electric Service Regulations of the Association on file with and approved by the Arizona Corporation Commission, including future applicable amendments, will be considered as forming a part of and incorporated in said Agreement.

TERMS OF PAYMENT: Credits due under this account will be credited to the Primary Service Account.

EFFECTIVE: XXXXXXX